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3. ***Consistent with the requirement in our IRP Order, PREPA shall establish and update semiannually a database of its renewable energy contracts, for all projects whether or not operational. This database shall include the names, owners, contract numbers, initial energy costs, current energy costs, initial REC costs, current REC costs, any relevant escalators, and expected and actual on-line dates. The format used in response to CEPR-AH-03-02 is acceptable but not binding.***

C. Capital expenditures

162. PREPA proposes new capital expenditures in FY2017 of $336.6 million, to be collected from ratepayers in this fiscal year. The FY2017 amount consists of $232.1 million for maintenance capital, $56.3 million for the Aguirre Offshore Gasport ("AOGP") and $48.2 million for transmission and distribution projects.[134] This amount is comparable to PREPA's CapEx in FY2013 ($360.1 million) and FY2014 ($316.0 million), but is much higher than PREPA's CapEx in FY2015 ($201.1 million) or FY2016 ($140.4 million).

1. Challenges in projecting capital expenditures

a. The distinction between operating expenses and capital expenditures

163. A transparent approach to setting budgets and revenue requirements requires a clear distinction between a capital expenditure and maintenance expenditure.

164. Operating and maintenance ("O&M") expenses are the expenses required to run the utility day-to-day. For a utility's physical infrastructure (generation, transmission, and distribution), this category includes the repairs and maintenance customarily required to keep an asset operating efficiently and reliably. Accounting principles require recording these costs in the year incurred. Regulatory principles normally require these costs to be recovered from ratepayers in the year incurred.

165. Capital costs are, in contrast, long-lasting. They are associated with new units or equipment, or with expenditures that increase the useful life of an existing unit. Instead of being expensed in the year occurred, they are usually amortized (*i.e.*, spread over the life of the associated equipment). In that way, the customers who benefit are the ones that pay, rather than causing this year's customers to pay for benefits enjoyed by later customers.

166. For a deteriorated plant, the distinction between operating expense and capital expenditure is not always clear. Ordinary repairs might not keep it operational. Temporarily patching a boiler is an operational expense, because the patch will not last multiple years.

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[134] See PREPA Ex. 3.0 at 45 and PREPA Schedule F-3 REV.

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Replacing the boiler in the next major outage cycle is a capital expenditure because it will last multiple years. Many of PREPA's proposed expenditures fall into this second category.

167. Part Two-II.B explained that, until PREPA gains access to capital markets, today's ratepayers must pay for both types of expenditures, operating and capital, in the year incurred. PREPA ratepayers therefore will be paying currently for some capital projects in whole, paying this year's portion of projects begun before this year and continuing after this year, and paying for the first part of projects whose completion might not occur until a later year.

b. Spending ceilings unrelated to system needs

168. In recent years, PREPA has based its capital budget on a compromise between the system's actual needs and a desire to avoid any rate increase (recall there has been no base rate increase since 1989). As PREPA explained:

> Historically, there has been political pressure to not increase PREPA's rates in response to cost and investment needs and therefore PREPA has had to sacrifice needed capital expenditures in order to remain solvent and to not run out of cash.[135]

This annual compromise produced a "top down" figure—a total budget cap for all capital expenditures, one driven not by system needs alone but by political considerations arising from hesitance to raise rates (or pressure from political actors not to raise rates). In other words, the main question was not "What do we need to spend to fix our system?" but "Given the premise of no rate increases, what can we spend?" This approach produced the following capital expenditure budgets:

FY2010: $350 million
FY2011: $300 million
FY2012: $327 million
FY2013: $300 million
FY2014: $300 million
FY2015: $245 million
FY2016: $245 million[136]

169. Artificial caps hide the truth. In future rate proceedings, PREPA must reveal truth: the total cost that must be incurred to meet the quality standards to which our citizens

[135] CEPR-SGH-01-08 at 10. Commission's Second Request of Information (June 23, 2016).

[136] Fisher-Horowitz Report at 75. PREPA underspent its budgets in FY2015 and FY2016. See Fig. 15 of the Fisher-Horowitz Report.

are entitled. Total cost means total cost: emergency purposes, preventive maintenance, system improvement, and system expansion.

170. A distinct problem arises when PREPA allocates amounts from the total capped budget to various departments. We were told by PREPA that the practice, with some exceptions, has been to allocate to each department the lower of that department's historic budget or its prior year's actual spending. This approach assumes, incorrectly, that the weighting of priorities among departments does not change.[137] It also encourages each department to spend its budget fully to avoid a reduction in the next year. Neither result substitutes for an annual rethinking of priorities, performed rigorously. PREPA needs to improve its budgeting process: how it sets priorities and how it develops, organizes and stores the information needed to make the best decision. We will address these concerns in our pending investigation on PREPA's performance.

171. But for this first base rate increase in over twenty-five years, the Commission will not require ratepayers to pay for the full amount spending necessary to satisfy PREPA's infrastructure needs. To try to make up for years of under-spending would be too harsh for customers. Nor could PREPA spend those dollars efficiently, given the limited time remaining in the fiscal year and the shortage skilled workers. Furthermore, there needs to be more rigorous budgeting and recordkeeping before we approve higher spending levels. We emphasize, however, the "top-down" budgeting approach that we are forced to accept here must not and will not continue. Rather than continuing to spend in reaction to system breakdowns, PREPA must invest in a reliable future. At the Technical Hearing, most of PREPA's witnesses made clear that they are willing and ready to abandon the historic approach and embrace the right approach. This Commission will insist on PREPA's doing so.

c. The nature of Commission's review

172. PREPA's capital expenditure request for FY2017 lists 402 items, with stated amounts ranging from zero to $20 million. The items are diverse: refurbishing individual turbines or generators; building new poles and lines; acquiring advanced transmission and distribution equipment; ordering new utility vehicles, computer systems, and network equipment, among others.

173. A thorough evaluation of PREPA's budgeting and spending requires a team of engineers and auditors. These assets are not presently available to the Commission. Even if they were available, the short 180 days statutorily available for this first rate proceeding would have been insufficient to deploy them effectively. We will use the upcoming performance proceeding to deploy the necessary expertise. But in this proceeding it was not practical, or wise, to attempt to review the reasonableness of every dollar.

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[137] However, it appears that some consideration is given to individual department requests arising from each department's determination of its needs. Directors ask for what they need; their requests are considered by top executives; then directors are given a budget amount.

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174. Among the challenges facing the Commission was transparency. While PREPA made serious efforts to provide the information we required, answering hundreds of questions, the information provided was often insufficient. Documents did not always make clear the purpose of a capital project, its prior spending, its progress toward completion or the predicted final cost. Often PREPA presented for a project a single number representing spending for a single year. That number did not inform us about the past or the future, because a line item in the FY2017 capital budget is only a fraction of a larger project. One must understand the full picture: When did the project start, when will it end, and is the spending this year and thus far consistent with the total budget? Without this information, we cannot know the project's purpose, its reasonableness as a solution to a problem, or the reasonableness of the project cost. PREPA's presentation often left us unable to determine whether a project's progress and spending coincided with an established schedule.

175. Contributing to the problem was dispersed records. When asked for work orders or contracts for engineering, procurement and construction ("EPC") for projects, PREPA responded:

> PREPA does not have electronic systems configured to be able to assess automatically which work orders are associated with a particular [capital expenditure] project; most of this information is on paper records. And those paper records are not organized by project in a central location. Further answering, the process of preparing the [capital expenditure] budgets start in PREPA's transmission and distribution districts, generating plants, customer service offices, among others.[138]

PREPA further explained:

> The particular details of each project are managed locally, not at a central location. Once the final complied spending limits are met, the plan can go through the final approvals. Regarding projects with no money spent, any documents reflecting the corresponding justifications and related information is located in the multiple generation plants, distribution offices, customer service areas, and other offices or departments that are responsible for or use that [capital expenditure] project.[139]

176. This dispersion of information meant that PREPA could not provide sufficient documentation explaining a project, justifying its expense, how the estimate was generated, or even the project's value to customers. As our consultants explained, with respect to specific capital projects PREPA was often "unable to provide basic explanations, work-plans,

[138] CEPR-AH-02-02(c) at 1. Commission's Sixth Request of Information (July 29, 2016).

[139] *Id.*

or other due diligence documentation [...]". The consultants thus had to "assess separate records of generator operations, forced outages, historic spending, and explanations scattered across dozens of disparate data responses to even begin to gain a coherent view of the state of PREPA's system, their needs, and the value of the projects requested by PREPA."[140]

177. Given these limitations, the Commission focused on capital spending areas raising obvious questions, while accepting PREPA's other proposed numbers for this rate year. For the lack of organized documentation does not change the reality that more spending is necessary to fix PREPA's system. We grant the approvals below, however, subject to the strict condition that PREPA complies with the budgeting procedures and transparency requirements established throughout this Order.

* * *

178. In the following subparts we will address the proposed capital expenditures for each of the following areas:

Generating plant
Aguirre Offshore Gasport
Transmission
Distribution
Transportation and Computer Equipment

We will close by stating our overall findings on capital expenditures in the revenue requirement.

2. Generating plant

179. Part One-III described, in general terms, the deterioration of PREPA's generation fleet. Merely beginning the process of restoration—the minimum necessary to keep the system operating—will require hundreds of millions of dollars. For each of the major generating plant, we address first the challenges it faces, then address how PREPA's proposed capital budget responds to those challenges.

a. Aguirre steam units

180. Aguirre is a 1,492 MW plant near Salinas. It is the largest single plant in the PREPA system, making up 26% of PREPA's generating capacity. It has three subcomponents: a steam power plant (900 MW), a combined cycle power plant (520 MW), and a simple cycle power block (72 MW). The Aguirre steam power plant, built in 1975, is itself divided into two electrical generating units of 450 MW each, both fired by heavy fuel oil. These steam

[140] Fisher-Horowitz Report at 80.

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units are the largest central station generators on PREPA's system, representing 16% of system capacity.

(i) Outage problems

181. Forced outages occur when a generator either automatically turns off or is brought offline for a mechanical, safety, or environmental problem or violation. A unit's high forced outage rate signals need for repair, chronic operational problem or susceptibility to operator error.

182. From 2012 to 2014 (calendar year), the Aguirre Steam Units on average had an unexpected outage during 612 hours, or twenty-five and a half days every year.[141] In 2015, Aguirre Steam Unit 1 suffered an extended outage from mid-July to the end of the year.[142] Aguirre Steam Unit 2 had another outage starting December 1st of 2015. The turbine remained offline through the last provided record in August 2016, for an outage of 246 days. The result was a combined forced outage rate of 27% in 2015 and 46% in 2016.

183. This record makes clear that PREPA's largest units are not reliable. Drs. Fisher and Horowitz concluded that "such sequential failures are not a function of normal wear and tear or aging, but are indicative of systematic maintenance failures, a failure to perform predictive maintenance, operational errors, and faulty repairs."[143]

(ii) Relationship to AOGP

184. The Aguirre Steam Units are not compliant with EPA's Mercury and Air Toxics Standard ("MATS"). PREPA's strategy for MATS compliance at Aguirre is to switch these units from oil to natural gas, using gas provided by the AOGP project (discussed in Part Two-III(C)(3) below). PREPA treats this conversion, along with the construction of the offshore gasport and associated facilities, as a single capital expenditure. But the Aguirre Steam Units need capital expenditures regardless of their connection to AOGP.

185. Determining the reasonableness of these expenditures is complicated. On the plus side, improving these units' performance will improve PREPA's reliability, while avoiding the need to operate more expensive backup units. On the negative side, extending the Aguirre units' lives will not be economical if the Commission ultimately rejects AOGP in favor of replacing the Aguirre units. Under PREPA's IRP plan, the Aguirre Steam Units would retire in 2026 and 2027, respectively.[144] With this plan (which assumes AOGP), continued

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141 CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information (July 29, 2016).

142 *Id.* Log of forced outages.

143 Fisher-Horowitz Report at 90.

144 PREPA Base IRP (August 17, 2015). Table 7-4.

capital investments make sense, to ensure reliable operation for another decade. But if the upcoming AOGP Economic Analysis causes the Commission to reject AOGP in favor of other options, logic dictates making only those investments at Aguirre necessary to ensure continued operation and reliability for the units' remaining lives.

(iii) Proposed capital expenditures

186. For FY2017, PREPA estimates $27 million in capital expenditures at the Aguirre Steam Units. That one-year cost is part of a multi-year project. For FY2017-2019, PREPA anticipates capital expenditures of $65 million, mostly for rehabilitating turbines and boilers. The $27 million amount represents both the tail of spending begun in prior years, as well the start of spending for projects expected to extend through FY2018 and FY2019. Combined with the natural gas conversion projects, PREPA is planning on spending $114 million in capital on the Aguirre Steam Units between FY2017-2019. The spending discussed here accounts only for projects that are currently planned in the next two years. There is a possibility that between now and 2019, PREPA will plan, scope and budget for additional capital projects at the Aguirre Steam Units.

187. PREPA has already started a series of retrofits of the boiler, turbine and generator at Aguirre Unit 2. While PREPA says these efforts aim to extend that unit's useful life, the turbine rehabilitation effort coincides with the failure of the turbine in November 2015.[145] Our consultants concluded that PREPA requires at least minimum capital to keep these units available while the Commission determines whether they should be continued through 2027 or be replaced sooner.

188. Drs. Fisher and Horowitz stated they were unable to assess whether the amounts proposed by PREPA matched well with the specific proposed projects. They did find, however, that PREPA's total anticipated expenditure at the Aguirre Steam Units, averaging $24/kW from 2017-2019 for non-AOGP projects, was consistent with "run-rate" capital dollars budgeted for steam coal units at other utilities.[146]

b. Costa Sur steam units

189. Costa Sur Plant is a 990 MW plant near Guayanilla. It is the second largest single plant in the PREPA system, making up about 17% of PREPA's capacity. It consists of four steam boiler electrical generating units: two sized at 85 MW and two sized at 410 MW.[147] The Costa Sur units are designed to be fired by residual fuel oil (No. 6).[148] Since 2012, Costa

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[145] CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information (July 29, 2016).

[146] Fisher-Horowitz Report at 94.

[147] PREPA Base IRP, August 17, 2015. Table 3-1.

[148] *Id.*

Sur Units 5 & 6, the larger units at the plant, have been fired with approximately 60-80% natural gas acquired from Gas Natural Fenosa, the majority owner of the EcoEléctrica power plant.[149] The fractions of gas and oil burned at Units 5 & 6 has varied over time, but is rarely less than 60%.

(i) Operations

190. For the last five years, the larger two units at Costa Sur have operated with an average capacity of 65%, making them the highest utilization units on the PREPA system. From calendar year 2012 through 2015, they maintained an average availability of 97%.

191. The smaller two units at Costa Sur, 3 & 4, are not MATS-compliant. To comply with MATS, PREPA has designated these units as "limited use," requiring them to operate below an 8% capacity factor starting in FY2016. In FY2016 Costa Sur 3 had a capacity factor of 11.3%.

(ii) Proposed capital expenditures

192. PREPA anticipates spending $7.4 million on capital improvements at Costa Sur Units 5 & 6 in FY2017. As the plant moves into a seven-year overhaul cycle, that level will increase through FY2020, due to investments in boilers and turbines, and modifications to the cooling intake and discharge systems to meet environmental regulatory requirements. PREPA does not propose any capital expenditures at Costa Sur 3 & 4, even though these units were used in FY2016, and even though PREPA's long-term plans designated these units for backup capacity.

193. Drs. Fisher and Horowitz concluded that the proposed capital expenditures for the boiler and turbine refurbishment are in line with similar projects envisioned by PREPA and seen elsewhere. They also found that PREPA's total anticipated spending at the Aguirre Steam Units, averaging $16/kW from 2017-2019, are in line with "run-rate" capital dollars budgeted for steam coal units at other utilities.[150]

c. Palo Seco steam units

194. The Palo Seco Plant has four large generating units located about two linear miles from downtown Old San Juan. Palo Seco's arrangement resembles Costa Sur's, but is smaller. Palo Seco 1 & 2 are 85 MW each, while Palo Seco 3 & 4 are 216 MW each. PREPA maintains simple cycle turbines at the Palo Seco site. Palo Seco was designed to be fired by heavy fuel oil (No. 6). At 602 MW, the Palo Seco Plant is PREPA's fourth largest plant, making

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[149] Percentages by equivalent heat content. CEPR-AH-06-01at 1. Commission's Fourteen Request of Information (September 30, 2016).

[150] Fisher-Horowitz Report at 97.

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up about 10% of PREPA's capacity. These units are a fundamental part of PREPA's northern fleet.

(i) MATS compliance and forced outages

195. Palo Seco's steam units are not MATS-compliant. PREPA has designated the two smaller units as "limited use," but the larger units lack a specific compliance strategy. PREPA has stated that "Siemens assumes that PREPA enters into a settlement agreement with EPA regarding Palo Seco 3 & 4 steam units (with a total capacity of 432 MW) allowing these units to continue operation burning No. 6 fuel oil through December 31, 2020. After that they will be either replaced or designated as a limited use unit."[151] Under this strategy, PREPA must be able to replace the Palo Seco units expeditiously.

196. The "limited use" designation for Palo Seco 1 & 2 required those units to operate at a capacity factor below 8%, starting in April 2015. But in FY2016, both units had capacity factors of 39% and 44%, respectively.[152] PREPA has explained that for Palo Seco 1 & 2 to satisfy the "limited use" designation, PREPA's other units, particularly those at San Juan and Palo Seco, need to be operating consistently. They are operating inconsistently. Palo Seco 3 & 4 had substantial outages, while PREPA does not expect Palo Seco 4 to be back in full service until January 2017.[153]

197. Palo Seco 3 & 4 has suffered outages exceeding those at the Aguirre Steam Units. Like Aguirre, Palo Seco experienced marked increases in the forced outage rate in 2014 and 2015. In 2015, Palo Seco's steam units was available about 65% of the time; in 2012 and 2013 their availability was 97% and 94%, respectively. At least as of August 2016, Palo Seco 4 has remained out of service.[154] Overall, Palo Seco 4 stayed on forced outage for over a year and a half, with only two months of actual operation in that time. Palo Seco 3 has had a similar history of forced outages, beginning in October 2015.[155]

(ii) Proposed capital expenditures

198. For FY2017, PREPA proposes capital spending at Palo Seco Units 3 & 4 of $8.5 million. The largest single project, PID 13448 ("Turbine Generator Improvement") is a

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[151] PREPA Base IRP, August 17, 2015. Section 7-5.

[152] CEPR-AH-03-07 Attach 01 at 5. Commission's Seventh Request of Information. (August 12, 2016).

[153] CEPR-JF-01-10(c) at 7. Commission's Sixth Request of Information. (July 29, 2016).

[154] CEPR-AH-06-06(a)at 6. Commission's Fourteen Request of Information. (September 30, 2016)

[155] CEPR-JF-01-16 Attach 02 at 3. Commission's Sixth Request of Information. (July 29, 2016).

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full overhaul of the turbine at Palo Seco 4 to bring it back to service. PREPA has not proposed capital expenditures at Palo Seco 1 & 2, even though it intends those units to provide backup capacity as "limited use" units. Drs. Fisher and Horowitz state it is unclear whether these units can stay within 8% capacity factor, given the need for generation in the north due to outages at PREPA's other northern plants.[156]

d. San Juan Steam units

199. The San Juan Steam Plant has four 100 MW steam units. They were built between 1965-1969, making this plant PREPA's oldest. The San Juan Steam Units were designed to be fired by residual fuel oil (No. 6).

(i) MATS compliance and forced outages

200. PREPA intends to designate San Juan 7 & 8 as "limited use." It is also seeking leniency for San Juan 9 and 10. PREPA has argued that it cannot designate San Juan 9 & 10 as limited use because they are "critical reliability units." PREPA plans to convert them to "burn natural gas on a dual-fuel scenario with Bunker C [No. 6] fuel oil."[157]

201. That conversion to natural gas would require a source of natural gas, but PREPA has stated: "While gas to the North could potentially be achieved via LNG infrastructure in the North or a South-to-North gas pipeline, the feasibility of either option is yet to be evaluated."[158] In the meantime, for the last five years San Juan 7 & 8 have operated at a 60% capacity factor, well above the 8% cap for "limited use" status.

These inconsistencies leave us with uncertainties. The following questions remain unanswered:

1. What PREPA can do to achieve reasonable MATS compliance at San Juan Plant.

2. What steps PREPA is taking to achieve MATS compliance at San Juan 9 & 10.

3. What expectations have been set with EPA with respect to MATS compliance at San Juan 9 & 10.

4. Whether PREPA still relies on the assumption that San Juan 9 & 10 will be converted to natural gas with a "gas to the north" scenario.

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[156] Fisher-Horowitz Report at 100-101.

[157] CEPR-JF-01-10 Attach 01. Early Notice of Compliance Plan, Mercury and Air Toxics Standards ("MATS") pages 9-10. Commission's Sixth Request of Information. (July 29, 2016).

[158] PREPA 2015 Integrated Resource Plan, Section 6.3.1.

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5. How the suboptimal operational record at San Juan 10 comports with PREPA's assertion that this unit is critical for reliability in the north of Puerto Rico.

6. How PREPA expects to meet the limited use designation for San Juan 7 & 8.

Like Palo Seco and Aguirre Steam Plants, San Juan Steam Plant has experienced increases in forced outages in the last two years.[159] In calendar year 2015, San Juan 10 had effective availability of about 18%. The unit is still offline and PREPA does not expect a return to service until mid-2017.[160] San Juan 9 had a series of outages in mid-2015, but has generally remained serviceable over the last six months with relatively minor outages. San Juan 7 & 8 have maintained better availability than the other units.

(ii) Proposed capital expenditures

202. For FY2017, PREPA proposes to spend $200,000 at all of San Juan Steam Plants (for FY2019 PREPA proposes to spend $15 million for improvements to the turbines and boilers at San Juan 9 & 10). Drs. Fisher and Horowitz concluded that the low spending level for FY2017 is inconsistent with these units' reliability problems, given their stated critical role. They reason that if these plants are not needed for reliability, they should be retired; if they are needed, then small dollars will not solve their large outage problems.[161]

e. Aguirre and San Juan combined cycle units

203. The Aguirre and San Juan Combined Cycle ("CC") Units are the only combined cycle units in PREPA's current fleet. They are composed of combustion turbine ("CT") units and heat recovery steam generators ("HRSG"). These components enable them to use the waste heat produced by the combustion turbine to create additional electricity. Both sets of combined cycle units burn diesel fuel. The two Aguirre CC units have nameplate capacities each of 296 MW; PREPA rates each at 260 MW, for a total of 520 MW. The units were built in 1977 and have a very high heat rate (*i.e.*, low efficiency, in terms of amount of fuel necessary to create a unit of electricity). The two San Juan CC units have nameplate capacities each of 220 MW, but are rated by PREPA at 200 MW for a total of 400 MW. The units were built in 2008 and 2009. As newer units, they have relatively low heat rates (*i.e.*, high efficiency).

204. PREPA did not provide forced outage records or estimates for the Aguirre Combined Cycle units. PREPA's 2015 IRP did model a forced outage rate of 20%.

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159 Fisher-Horowitz Report at 102.

160 CEPR-JF-01-10(c) at 7. Commission's Sixth Request of Information. (July 29, 2016).

161 Fisher-Horowitz Report at 105.

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(i) Plans for these units

205. In its IRP decision, the Commission ordered PREPA to pursue permitting and start a competitive bidding process for the repowering of the Aguirre 1 and 2 CC units with new, dual-fuel capable turbines.[162] Neither the repowering nor the planning or permitting costs for the repowering are part of PREPA's petition for a FY2017 rate increase.

206. In its 2015 IRP submission, PREPA proposed to convert the Aguirre CC to operate as a gas-fired facility starting in 2018, with the conversion coinciding with AOGP. PREPA's rate proposal includes the gas conversion at Aguirre CC with the AOGP project. PREPA has not yet signed a contract for this work, but has had informal discussions with General Electric.

(ii) Proposed capital expenditures

207. According to Drs. Fisher and Horowitz, the Company's modeling indicates that a repowered Aguirre CC unit, operating with a lower heat rate and better reliability, can support a plan to retire the Palo Seco and San Juan steam units. Yet PREPA proposes to spend on Aguirre CC only $17.8 million from FY2017 to FY2019, mostly for scheduled maintenance and "automation" systems. This amount is comparable to what PREPA spent in FY2016—yet according to Drs. Fisher and Horowitz, outages at Aguirre CC are preventing this unit from contributing reliably. PREPA seeks to make the gas conversion of the Aguirre CC a key component of the AOGP project and gasification of the south. These factors are in conflict with the low spending level proposed.

208. In contrast, at San Juan CC plant, PREPA proposes to spend $40.8 million from FY2017 to FY2019. One contributor to this cost is a maintenance contract from Mitsubishi-Hitachi ("MHPS-PR") to service the combustion turbines and generators (PIDs 16945 & 16946). This long-term agreement, signed in March 2016, extends and expands the scope of services provided by MHPS-PR from technical support and assistance to a full maintenance contract. Because this contract is specifically associated with the regular maintenance of the generator, the costs of this contract should be considered an operations and maintenance ("O&M") expense rather than a capital cost. One PREPA witness explained that if the unit is not in service, Mitsubishi does not get paid. This contract feature, he argued, reduces the need for a review of Mitsubishi's performance.

f. Cambalache and Mayagüez combustion turbine units

209. Cambalache and Mayagüez are two CTs (also known as "gas turbines") that burn diesel. Cambalache, near Arecibo on the northern central coast, has three power blocks of 83 MW each, totaling 249 MW. It was built in 1997-1998. Mayagüez station, located on the

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[162] Final IRP Order, Part VII(B)(1)(c).

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west coast, has four power blocks at approximately 50 MW each, or 200 MW. Mayagüez began operation in 2009.

(i) Outage problems

210. The Consulting Engineer's 2013 Report discussed a critical failure at the Cambalache plant when a control system fault led to the buildup of unburnt fuel in a turbine, leading to an explosion that severely damaged Unit 1.[163] The same report discusses more minor outages at Mayagüez, including an incorrectly installed turbine that required modification under warranty.

(ii) Expenditures on maintenance contracts

211. PREPA's proposed expenditures consist entirely of flat fees for "inspections" at Cambalache (PID 15880) and "improvement" at Mayagüez (PID 16978). At Cambalache, the inspection represents an ongoing service contract with Alstom, valued at $4 million per year. At Mayagüez, PREPA simply indicates a flat $600,000 per year "improvement." It is unclear why PREPA anticipates spending $4 million per year at the older, less efficient 249 MW Cambalache plant, while spending a much lower amount at the newer, more efficient Mayagüez station.

212. The primary spending at Cambalache is a maintenance contract with contractor Alstom Caribe (now a division of GE Power). The twelve-year contract, signed in May 2011, is designed to provide an inspection and refurbishment of combustion turbines and generators every two and a half years. Like the San Juan CC maintenance contract, Alstom divides maintenance into cycles, denoted as "A" through "D" inspections. "A" inspections occur approximately every month and a half (1,000 hours) and include preventative maintenance. "B" inspections occur every year and half (12,500 hours) and include the disassembly of the turbine unit for closer review. "C" inspections, every two and a half to three years (25,000 hours), include the refurbishment of the turbine and combustion chamber. Finally, "D" inspections, every five to seven years (50,000 hours), entail the refurbishment or replacement of any worn component in the generator or turbine.[164] The maintenance contract at Cambalache is specifically geared to the "C" inspection cycle.

213. Maintenance responsibilities under the contract are split between PREPA and Alstom, where Alstom provides turbine cleaning, inspection and refurbishment services, but

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[163] URS June 2013 Annual Report at 27.

[164] *Id.* at 6-7.

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PREPA "employees are responsible for the installation of replacement parts,"[165] ~~and day-to-~~ day operations and site maintenance.[166]

214. The "C" inspections provided under this contract fall into standard ongoing maintenance cycles. Because this contract is specifically associated with the regular maintenance of the generator, the costs of this contract should be treated as an O&M expense rather than a capital cost.

215. While the contract requires that Alstom provide a "permanent on-site operations and maintenance advisor,"[167] and provides a "technical field advisor" for "A" and "B" inspections, the contract does not actually specify the role of the technical field advisor, who leads the inspection and refurbishment process and, most importantly, who bears responsibility for correctly executed inspections, maintenance, and replacement.

216. The contract limits Alstom's liability for PREPA staff negligence or deficiencies. Alstom included a contract provision "exclud[ing] any and all liquidated damages for outage schedule delays, unless such delay is 100% attributable to a negligent act or omission of ALSTOM (*i.e.*, ALSTOM fails to deliver a correct part or make available the required personnel and such late delivery/performance causes an outage delay)."[168]

217. Since PREPA did not provide a record of forced outages at Cambalache, including any reasons for outages or delays, the Commission's consultants were unable to evaluate Alstom's performance. There was a two-year outage at Cambalache arising from a control system failure that caused an explosion in the turbine.[169]

218. According to our consultants, the Cambalache contract has no performance incentives or penalties to keep the units in operation or in a state of good repair. Alstom's liabilities are limited to a small fraction of the cost of the contract.[170]

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165 *Id.* at 26.

166 Alstom Cambalache 2011 Contract at ¶ 1.5 and Appendix 1.

167 *Id.* at ¶ 1.1(h)

168 *Id.* at ¶ 1.1(f).

169 URS June 2013 Annual Report, Page 27.

170 Alstom Cambalache 2011 Contract at ¶ 8.3.

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Directives

1. *The FY2017 revenue requirement shall include the full proposed capital spending at Aguirre, Costa Sur 5 & 6, Palo Seco, and San Juan Steam Plants, as well as the $600,000 FY2017 improvements at Mayagüez.*

2. *PREPA shall remove the maintenance contract at San Juan CC from the capital budget and reassigned it as an annual maintenance expense, a reassignment of $12 million in FY2017 from capital to O&M. PREPA shall remove the cost of the Cambalache maintenance contract from the capital budget and reassign it as an annual maintenance expense—a reassignment of $4 million in FY2017 from capital to O&M. Attachment 1 shows increased PREPA's Generation Expense by $16 million, as discussed above.*[171]

3. *PREPA shall track capital expenses associated with each generating unit designated as "limited use." Such tracking shall be performed for each individual unit. To the extent capital expenditures at a plant site are not separable by unit, PREPA shall associate those expenditures in the tracking record by the units that benefit from the capital or, if applicable, designate an expenditure as "whole plant." In addition to, or as part of this tracking, PREPA shall:*

   a. *submit periodic reports on capital projects at Palo Seco 1 & 2, regardless of whether these units are designated "limited use. "*

   b. *submit periodic reports on capital projects at San Juan 7-10, regardless of whether these units are deemed "limited use."*

   c. *submit periodic reports on capital projects at Costa Sur 3 & 4, regardless of whether these units are deemed "limited use."*

4. *PREPA shall submit strategic plans for the San Juan and Palo Seco steam plants, including the following elements, at a minimum: maintenance plan, MATS compliance plan, and an investment plan for maintaining or retiring San Juan 7-10 and Palo Seco 1 & 2. These plans shall be informed by a reliability study, assessing what strains are placed on the generation and transmission system in the presence or absence of the San Juan or the Palo Seco steam units.*

5. *PREPA's long-term modeling, including for integrated resource planning, shall consistently assess whether each generating unit designated as*

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[171] See Attachment 3, at 3.

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"limited use" is available for reliability purposes; and if not, assess the value of maintaining units that neither contribute to peak purposes nor provide energy to the system.

6. *In its next submission within the integrated resource planning process, PREPA shall assess the economic value to ratepayers of maintaining each "limited use" unit, as compared to retiring such unit.*

7. *In the upcoming performance proceeding, the Commission shall consider whether to require PREPA submit to the Commission at least three qualified consultants, one of which the Commission will select and retain, to:*

    a. *examine the maintenance contract at San Juan combined cycle plants and the performance of MHPS-PR to determine if the contractor is meeting performance expectations for maintenance service.*

    b. *examine the Cambalache contract and the performance of Alstom to determine if the contractor is meeting performance expectations for maintenance service at Cambalache.*

8. *PREPA shall submit for Commission approval, prior to its execution, any long-term contract with service providers with a potential net present value of $25 million or higher.*

9. *PREPA shall submit a summary of the expenditures necessitated by the fire and outage occurring in September 2016.*[172]

3. Aguirre Offshore Gasport

a. Overview

219. The Aguirre Offshore Gasport ("AOGP") is a re-gasification facility. Its purpose is to allow the Aguirre Steam and Aguirre Combined Cycle units (collectively "Aguirre Plant")

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[172] PREPA opposes this requirement, arguing that the fire did not affect the revenue requirement in the current test year and that the Commission can investigate the costs in a future reconciliation proceeding. PREPA is missing the point, emphasized throughout this Part Two and articulated procedurally in Part Four: The Commission intends to avoid situations in which PREPA incurs costs first, then tells the Commission in a reconciliation proceeding that the Commission has no choice but to approve them because they have already been incurred. To protect consumers, the Commission must reserve its powers to evaluate costs before they are incurred. PREPA must not view the reconciliation process as allowing it to incur costs without accountability.

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access to natural gas shipped to Puerto Rico as liquefied natural gas ("LNG"). As discussed here, AOGP includes four interlinked projects:

1. The offshore project: an LNG berthing platform and submerged pipeline connecting the offshore project to the Aguirre Plant site;

2. The onshore project: a pipeline from Jobos Bay to the Aguirre Plant facilities;

3. The combined cycle conversion project: the installation of natural gas burners and control equipment at Aguirre Combined Cycle Units 1 and 2; and

4. The Units 1 & 2 conversion project: the installation of natural gas burners, boiler modifications, and control equipment at Aguirre Steam Units 1 and 2.

On completion, AOGP's vendor, Excelerate, would dock a Floating Storage and Regasification Unit ("FSRU") at the offshore port. Arriving tankers would transfer LNG to the FSRU, which would decompress the LNG on an as-needed basis, shipping the decompressed natural gas through an undersea pipeline to the Aguirre Plant.[173] Permitting and engineering for the facility are ongoing.

220. PREPA says AOGP has four main benefits. It "would (1) contribute to the diversification of energy sources in Puerto Rico, (2) allow the Aguirre Plant to meet the requirements of the EPA's MATS rule, (3) reduce fuel oil barge traffic in Jobos Bay, and (4) contribute to energy price stabilization in the region."

b. Capital cost

221. PREPA proposes to include in its revenue requirement $56.3 million in FY2017 and $413.3 million in FY2018.

222. When it submitted its rate case request, PREPA estimated the total AOGP cost at $552 million, including financing costs. As detailed in the Fisher-Horowitz Report, that total has undergone several changes and re-estimates. The $552 million figure does not include the 15-year contract with Excelerate, a 15-year commitment at $40.7 million per year (present value of $422 million). Unlike all other capital expenditures in this rate case, PREPA believes it can secure financing for AOGP, assisted by a U.S. Department of Energy ("DOE") loan guarantee, which PREPA is seeking for 80% of the project cost.[174] The $56.3 million in FY2017 represents a portion of the costs for which PREPA has not requested financing

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[173] Federal Energy Regulatory Commission, February 2015. Aguirre Offshore Gasport Project: Final Environmental Impact Statement (FEIS). Docket Nos. CP13-193-000 and PF12-4-000.

[174] Dr. Quintana has stated that the DOE assistance is not the only possible financing path. Ex. 13.00 ll. 177-179.

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support from DOE. Because the Commission will be limiting the FY2017 recovery to $15 million, we will defer a discussion of the budget details for when we make a final decision on the project.

c. Contracting

223. The Fisher-Horowitz report details the major contracts necessary to complete and operate AOGP, including contracts for the development of the offshore gasport itself ("Infrastructure Agreement"), the gas conversions of the Aguirre Plant units, the operation and maintenance of the gasport facilities ("Terminal Operation and Maintenance Agreement"), and the long-term rental of the FSRU facility ("Time Charter Party and LNG Storage and Regasification Agreement", or "Time Charter"), as well as other contracts for AOGP completion including engineering services, development of the environmental impact statement ("EIS"), the development and shepherding of other permits through Puerto Rico and federal agencies, and legal services.

d. Commission's IRP findings and PREPA's revised revenue requirement

224. In its Final Resolution and Order on PREPA's 2015 IRP, the Commission determined that it "cannot conclude that AOGP represents a least-cost, least-risk path for serving customers' needs and meeting Puerto Rico's energy policy goals based on the facts presented in this proceeding."[175] The Commission approved continued permitting, engineering and planning activities in the overall AOGP project, subject to a $15 million spending cap. PREPA must obtain Commission permission before exceeding that cap—permission that will be withheld until there is a "detailed economic assessment" of AOGP. PREPA has sought reconsideration.

225. On September 27, 2016, the Commission in the instant rate proceeding required PREPA to re-file its revenue requirement exhibits and testimony to, among other things, reflect the $15 million cap on AOGP spending. The Commission made clear that the $15 million cap "applies to the total combined spending associated with AOGP and the gas conversions."

226. PREPA's revised revenue requirement did not make the required adjustment. PREPA argued, among other things, that "even if AOGP and the other generation projects in the north are not approved, PREPA's other significant investments would have to be made rapidly."[176] PREPA concluded that it "has no reason to believe that these alternative

[175] CEPR-AP-2015-0002 (Sept. 26, 2016) at ¶ 255.

[176] PREPA Ex. 13.00 at ll. 110-111.

investments would be any less expensive than the investments currently reflected in its three year business plan."[177]

227. This argument was unaccompanied by supporting evidence. The Commission therefore will retain the $15 million cap. If and when PREPA needs to incur additional costs for AOGP, it shall first seek and obtain Commission approval through the AOGP Economic Analysis as specified in the IRP Order. Similarly, if PREPA needs to incur costs for "alternative investments" it shall seek and obtain prior approval from this Commission. The $15 million limit specified in the IRP Order is a limit not only on FY2017 spending, but on project commitments as well. Until such time that it has received Commission approval, PREPA shall take no action under any contract that increases its financial obligations beyond those that currently exist.

228. PREPA has argued that preventing progress on AOGP risks incurring EPA fines. This argument is nearly synonymous with an argument that AOGP is the only option for satisfying MATS, such that rejecting AOGP make EPA finds certain. The Commission rejects that argument because it is unsupported by facts. PREPA itself has included no amounts for fines in its proposed revenue requirement. When the Commission receives from PREPA the economic analysis required by the IRP Order, and if based on that analysis the Commission finds that AOGP is the most cost-effective path to MATS compliance, it will reconsider PREPA's argument. And when PREPA has credible evidence that such fines are imminent, instead of generalized statements that do not take into account EPA practices and precedents on fines, it should bring that information to the Commission.

229. The Fisher-Horowitz Report states (at 131):

> [I]n the time that PREPA committed internally to the AOGP project it increasingly sidelined viable alternatives, including MATS-compliant new generation, environmental controls on existing generation, increased renewable penetration, a focus on smaller distributed generation, or the completion of a south coast gas pipeline. PREPA has presented little or no evidence that those options are not still viable.

230. PREPA's emphasis on AOGP has come at the expense of a permitted, licensed, and half-built pipeline from the EcoEléctrica facility to Aguirre. As Ms. Miranda stated, "based on the previous studies that we did to justify this project, the cancellation of the south gas pipeline in 2009 was not optimal."[178] As our consultants explained, PREPA has "narrowed its options for improving and expanding the current MATS-compliant fleet, and

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177 *Id.* at ll. 106-116.

178 CEPR-SGH-001-016(a)-Supplemental at 22. Commission's Second Request of Information (June 23, 2016).

seeking substantial renewable energy."[179] Instead, by relying on Aguirre, PREPA has "created a fleet that, by its own measure, cannot effectively take on renewable energy simply because its existing generators ramp too slowly."[180]

e. Directives

(i) ***Consistent with the IRP Order, PREPA shall limit spending on AOGP to $15 million, reducing FY2017 revenue requirements by $41,340,000.***[181]

(iii) ***PREPA shall not sign a Limited Notice to Proceed or a Final Notice to Proceed at AOGP until it has submitted, and the Commission has approved, the AOGP Economic Analysis; or until the Commission resolves the Reconsideration under review.***[182] ***PREPA shall make no other commitments to incur future costs relating to AOGP without submitting a request and documentation to the Commission. If the Commission approves AOGP, PREPA may request an increase in the revenue requirement.***

(iv) ***The Commission recognizes, as the Fisher-Horowitz Report says, that "[s]talling projects, cancelling vendors, or missing contractual deadlines could result in increased costs, damages, or potential legal actions by vendors." PREPA shall alert the Commission promptly—and factually—if such possibilities become imminent realities.***

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179 Fisher-Horowitz Report at 39.

180 *Id.* at 39.

181 *See* Attachment 3, page 2.

182 PREPA in its brief opposes this requirement on grounds that it is an issue pending in the IRP case. The Commission is imposing the requirement in this case to prevent PREPA from spending money that would then appear in a future request to increase customer rates, which increase would likely be accompanied by a PREPA argument that the Commission has no choice but to approve the increase because the costs already have been incurred. This type of situation is precisely the type that Dr. Hemphill never solved (see Part Four), and which PREPA's opposition here reveals to be a problem.

(v) If and when PREPA needs to incur additional costs for "alternative investments" (i.e., alternatives to AOGP), it shall first seek and obtain Commission approval. [183]

4. Transmission

a. Description of the transmission system

231. PREPA's transmission system consists of aerial and underground wires. It interconnects PREPA's large, central station generating plants, sited in four main locations in the north and south, with a distribution system serving population centers. The transmission system runs through mountains and wet tropical forests—some of the most difficult terrain in the U.S. As described in the URS 2013 Report (at 3):

> The Authority's transmission system is an interconnected network of 230 kV, 115 kV, and 38 kV power lines that carry electrical power from the production plants to numerous distribution centers from where it is distributed to clients for consumption.
>
> At the close of fiscal year 2013, the transmission system was comprised of 2,478 circuit miles of lines: 375 circuit miles of 230 kV lines, 727 circuit miles of 115 kV lines, and 1,376 circuit miles of 38 kV lines. Included in the transmission system totals are approximately 35 miles of underground 115 kV cable, 63 miles of underground 38 kV cable and 55 miles of 38 kV submarine cable. In addition to the high voltage lines, the transmission system includes transformers at the generating plant substations, transmission centers for interconnection of different voltage systems and switch yards and gear for connection or separation of portions of the transmission system operating at the same voltage. High voltage transformers installed in the Authority's transmission system and its production plants have a total transformer capacity of 19,207 MVA.

The Fisher-Horowitz Report adds:

> The 230 kV system essentially forms a ring around the island's less populous interior, connecting major cities and towns. In addition, PREPA maintains two substantial north-south corridors from Salinas (near Aguirre and the AES plant) to San Juan, and from Guayanilla (near EcoEléctrica and Costa Sur) to Arecibo and Manatí on the north coast. The primary operational thermal

[183] Windmar argues that PREPA should retire obsolete power plants and study replacing them with smaller, flexible and more efficient plants as required by Act 57-2014. This is an important recommendation that is consistent with the recommendations in the Fisher-Horowitz Report, our conclusions in this Order and the directions stated in our recent IRP Order.

generation in Puerto Rico is located on the south coast EcoEléctrica, Costa Sur, Aguirre, and AES coal plant. The transmission system is designed to facilitate the flow of energy from these plants to the primary population centers in the north. Cambalache, on the north coast near Arecibo, and Mayagüez, on the west coast, provide peaking generation.

b. Transmission system capital budget

232. PREPA proposes a FY2017 transmission revenue requirement of $81.3 million, spread over 100 separate line item projects.[184] About 68% of the proposed FY2017 spending is concentrated in the 230 kV and 115 kV systems, primarily on line rehabilitation. The proposed cost is about $50,000 per mile in FY2017 for those larger systems, less for the 38kV system.

233. Half of the FY2017 dollars proposed for transmission ($40.5 million) would replace structures, towers, foundations and insulators on high capacity transmission lines, including those in the following corridors:[185]

1. Two 230 kV lines (50900, 51000) from Aguirre to Aguas Buenas, just south of San Juan (south-north): $15.7 million.
2. 115 kV line (37800) from Jobos near AES to San Juan (south-north): $13.4 million
3. 115 kV line (37400) from Arecibo to San Juan (east-west): $4.4 million.
4. 115 kV line (36100) from Lago Dos Bocas towards Piñas, on the outskirts of San Juan. (east west): $7.0 million.

As in all of PREPA's other capital projects, these numbers represent the amounts to be incurred in FY2017, rather than total project costs. Drs. Fisher and Horowitz state that based on project data, PREPA expects to spend ultimately (not in FY2017 alone) about $600,000 per mile on the 230 kV system and, on average, about $700,000 per mile on the 115 kV system. Drs. Fisher and Horowitz view these costs as consistent with utility estimates for similar projects.

234. The largest component of the 38 kV capital budget for FY2017 is allocated to the rehabilitation of the 38 kV system. This category has 24 specific projects, only one of which exceeds $1 million. These smaller projects are described by PREPA as "improvements" and

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[184] See the Fisher-Horowitz Report at Table 15, consolidating PREPA's transmission capital budget by sub-area and initiative. See also PREPA's Schedule F-3 REV.

[185] Schedule F-3 REV.

"increase[s] [in] capacity." Our consultants found that these projects, and their costs, are consistent with PREPA's needs to strengthen the system. The only project exceeding $1 million in FY2017 is a reconstruction of seven miles of line near Mayagüez (PID 15610). This project replaces rotting wooden poles with steel, effectively re-building the line. The Fisher-Horowitz Report states that the cost is consistent with utility estimates for similar projects.[186]

235. In addition to the foregoing line-related costs, there are assorted non-line items, most of which according to Drs. Fisher and Horowitz are lower-cost, individual items whose reasonableness is difficult to assess without an engineering audit.

c. Directive

Based on the information provided by PREPA and its examination and assessment in the Fisher-Horowitz Report, as well as the discussion at the technical hearing, the Commission approves the full FY2017 transmission system capital budget as requested by PREPA.

5. Distribution

a. Description of the distribution system

236. The PREPA distribution system is divided into seven regions with 26 Technical Districts.[187] From the 2013 Consulting Engineers Report (at 17):

> As of June 30, 2013, the Authority's distribution system consisted of approximately 31,550 circuit miles of distribution lines (with operating voltages ranging from 4.16 to 13.2 kV) and 333 substations (with a total installed capacity of 5,018 MVA). The distribution system has more than 1,800 circuit miles of underground lines. The Authority has 22 portable transformers with a total capacity of 349.6 MVA to substitute for existing transformers during maintenance or outages; similarly, the Authority has two portable capacitor banks each rated at 18 MVAR. There are 813 privately owned substations (with a total installed capacity of 3,266 MVA). The distribution system also includes approximately 1,485,200 client meters.

237. Of the 31,550 circuit miles of distribution lines, approximately 24% are at 13.2kV, 24% at 8.32 kV, and the remaining overhead lines are at 4.16 kV.[188] Over 16,000

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186 Fisher-Horowitz Report at 139.

187 CEPR-AH-02-06 at 8. Commission's Sixth Request of Information (July 29, 2016).

188 URS June 2013 Annual Report at 55.

circuit miles are primary voltage.[189] In addition PREPA has approximately 3,100 circuit miles underground, three-quarters of which is 13kV.[190] PREPA also has approximately 333 substations. According to the URS 2013 Report:[191]

> The Authority has standardized on two sizes of permanent substations based on the transmission system supply voltage. This standardization expedites the engineering, procurement, and construction cycle, increases flexibility in potentially utilizing equipment as spares, and provides a cost effective installed capacity margin for load growth. In situations where the Authority needs additional substation capacity on an interim basis or with short lead times, the Authority installs temporary substations that are standardized unitized metal clad equipment, which can be relocated as required.

As with the transmission system, PREPA emphasizes the need for repair:

> In general, PREPA Distribution system is in operational state or condition, but with reliability concerns, due to aging of the components. Still a high percentage of overhead ("OH") distribution circuits are attached to wood poles in deteriorated conditions, with OH cables gages inappropriate to serve the electrical load in a reliable and qualitative manner. Taking a look to the underground ("UDG") Distribution circuits, a significant number of them have been replaced in "temporary" way by OH circuits thru street lights poles, to reestablish electrical service to customers when outages cannot be fixed repairing the UDG conductor. Most of the UDG circuits in residential communities (Urbanizations) with more than 30 years of existence are direct burial, which accelerate the cable deterioration and prevent replacing cables in reasonable time and avoid repeated interruptions in the future. This also increases the reconstruction and maintenance costs when intervention is required. In addition to the Distribution Electrical network (OH &UDG), the sites (substations) where main power distribution transformers reside are in advance state of deterioration. Most of the components need to be replaced and perform continuous maintenance to grounds and buildings.[192]

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[189] CEPR-AH-02-01 at 1. Commission's Sixth Request of Information (July 29, 2016). Primary voltage lines link transmission substations with transformers, which "step down" the electric current to secondary voltages so that it can be delivered to customers

[190] CEPR-JF-02-06(a) at 22. Commission's Seventh Request of Information (August 12, 2016).

[191] URS 2013 Report at 51.

[192] CEPR-AH-02-01(f) at 3. Commission's Sixth Request of Information (July 29, 2016).

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b. Distribution budget in general

238. PREPA proposes a FY2017 distribution capital budget of $74 million, spread over 108 line items. About 85% of the $74 million is for non-meter spending. Table 16 in the Fisher-Horowitz Report organizes the budget by sub-area and initiative.[193]

239. According to Drs. Fisher and Horowitz, most of the proposed spending is for rehabilitating the existing distribution system, substations, feeders and lines.[194] The spending includes $27.3 million for "blankets"—pools of money used as needed for repairs, maintenance and replacement parts. Another $12.5 million is allocated to new meters and meter equipment. The remainder (slightly over 50%) is targeted towards street lighting, along with rehabilitation of substations and feeders.

240. Of the 78 distribution projects that had FY2017 spending and were not either explicitly blankets or meters, the average FY2017 cost was well under one million dollars, with a median cost of about $250,000.

241. Assessing the reasonableness of these dollars was a challenge. Beyond calling them "required improvements," PREPA did not provide justification or explanations for the individual projects. Furthermore, PREPA's records of past capital spending were categorized differently from those associated with future spending. In a public technical conference call, however, PREPA's distribution staff answered questions thoroughly, in the opinion of Drs. Fisher and Horowitz, stressing that (a) the requested spending level was a necessary beginning to restoring the distribution system, and (b) the capital budgets were likely lower than required to ensure reasonable service. At the technical hearing, PREPA's witnesses re-emphasized these points.

c. Meter capital budget

242. PREPA has 1,620,401 installed meters, active and inactive.[195] For its FY2017 through 2019 revenue requirements, PREPA has requested $10.6 million per year to buy residential meters. This amount does not include maintenance or operating expense. These purchases are part of a replacement plan emphasizing equipment upgrades. PREPA would acquire in FY2017 29,000 meters, an estimated cost of $200/meter plus communication infrastructure. Installing new technology (advanced metering infrastructure—known as AMI or smart meters) adds approximately $198 per meter.[196]

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193 See also PREPA Schedule F-3 REV.

194 Fisher-Horowitz Report at 143.

195 CEPR-JF-02-05 at 19. Commission's Seventh Request of Information (August 12, 2016).

196 CEPR-AH-02-06 at 8. Commission's Sixth Request of Information (July 29, 2016).

243. As described by Drs. Fisher and Horowitz, smart meters are capable of two-way communication between individual meters and the utility. The two-way communications can provide "interval data" (data that is specific to short periods of time) at a level of frequency (*e.g.*, every 15 minutes) that radial and AMR meters cannot provide. Drs. Fisher and Horowitz questioned the cost-effectiveness of the additional cost of smart meter technology. They recommended that the Commission not approve the extra funds necessary for smart meters; rather, PREPA should install only the current meter models.

244. In 2015, PREPA initiated a pilot program to install 30,000 smart meters in two phases. A July 2015 presentation provided an overview of PREPA's goals (translated):

1. Gather the necessary data to raise the specifications of the optimal system for electric system.

2. Improve the efficiency of the electrical system.

3. Significantly improve the service offered to customers, such as SAIDI, SAIFI, CAIDI and thus reduce the need for management in the commercial offices and Customer Service Center (telephones).

4. Enable automatic remote disconnect and disconnect, to improve service and to allow service cut-off, thus improving cash flow.[197]

PREPA's goals in pursuing smart-grid technology are similar to those of other utilities installing smart grid.

245. Drs. Fisher and Horowitz assert that "[u]tilities have generally found it difficult to justify smart grid technology on a cost effectiveness basis."[198] While PREPA cited Hawaii as an example, Drs. Fisher and Horowitz found this example faulty, because "the deployment cost of $413 million would likely exceed the $345 million in estimated benefits for the project."[199] They also assert that a later PREPA presentation, in July 2016, "clearly indicates that the smart meter program would not be expected to provide cost savings, and is a distraction from PREPA's immediate requirements."[200] They also point out that over half the

[197] Commission's October 20, 2016 Clarification Call Request 161020 No.8 Attachment 1: Slide 3.

[198] Fisher-Horowitz Report at 147.

[199] Hawaiian Electric Companies, Application. Table 2, Page. 8. March 31, 2016. Docket 2016-0087.

[200] Fisher-Horowitz Report at 147.

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meters supplied had to be returned for re-calibration, and that the island's mountainous terrain will make cellular communication difficult.[201]

246. The Commission appreciates the efforts by PREPA and our own consultants to assess the benefits and costs of smart meters. We conclude that the efforts already begun, the small amount of dollars at stake, the potential to help consumers manage their consumption, justify this small continuation of an existing pilot program. Therefore, we will approve this funding request.

247. We do, however, share our consultants' concern with spending multiples of this amount in future years without a stronger business case.

d. Directives

(i) ***The Commission approves the full FY2017 distribution system capital budget as requested by PREPA. PREPA shall continue acquiring advanced meter reading ("AMR") meters unless a specific application requires advanced meter infrastructure ("AMI"). If PREPA wishes to acquire smart meters above the 30,000 already acquired without a specific technical application need, it shall submit a detailed business case describing and evaluating the costs and benefits of smart meter deployment. The business case should provide detail of the scope, scale and schedule of deployment, including but not limited to technological and financial issues. It should take into account the need for staff and consumer education for effective meter use.***

(ii) ***PREPA should not commit to any greater expenditure than what is approved here, without approval of the Commission.***

(iv) ***For future purchases of meters, PREPA shall use competitive bidding.***

6. Transportation and Computer Equipment

248. PREPA proposes $19.4 million for vehicles. PREPA maintains a fleet of 3,593 vehicles, of which approximately one-third are SUVs or basic pickup trucks. Another third of the vehicles are either trailers or highly specialized vehicles (such as bulldozers, cats,

201 *Id.* at 146-47.

trenchers and loaders). The remaining vehicles are either bucket trucks or other line vehicles. Another $3 million is for a replacement helicopter.

249. PREPA also proposes $13.1 million for computer equipment, data management systems and new network equipment. The most substantial request is a data center migration to PREPANetwork, costing $8 million ($6.3 million in FY2017). Using an affiliate (PREPANetwork) for the data center raises the concerns we discuss in Part Five-II. PREPA should have used competitive bidding to select the best provider. Given the immediate need to improve data collection, analysis and reporting, we will not delay this transaction. But future affiliate transactions must adhere to the principles discussed in Part Five-IV.

250. Given the small size of this area and our obvious focus on the larger questions of generation, transmission and distribution, and given that no red flags were raised by our consultants or the intervenors, we approve the full FY2017 transportation and computer equipment budget.

7. Overall findings on capital expenditures in the revenue requirement

251. PREPA shall include $153.462 million for capital expenditure in PREPA's revenue requirement. This is a reduction of approximately $183.096 million from PREPA's request of $336.558 million. Most of this reduction consists of reclassifications rather than actual reductions. Specifically, the $183.096 million reduction reflects the following (as explained in Attachment 3, page 2:

— $125.756 million is an adjustment for the amount of capital expenditure recognized in the debt service coverage ratio.

— $41.340 million reflects the required reduction in spending for AOGP.

— $16 million reflects reclassification of capital expenditures at Cambalache and San Juan to operations and maintenance expense.[202]

D. CILT and subsidies

252. PREPA has proposed specific amounts for the contribution in lieu of taxes ("CILT") and various other subsidies. Most of these items are required by statute. For most of these items, PREPA's proposed amounts are predictions, although some are fixed. In most situations, our statutes do not give us discretion to judge the reasonableness of these amounts. Furthermore, any variation between the predicted and actual amount will be

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[202] Another way to understand the $153.462 million is to take the original capital expenditure figure proposed by our consultants, shown on Smith-Day Ex.3 l. 23 as $148.662 million, and add back the $4.8 million for smart meters that our consultants had removed.

reconciled either in a specific rider (discussed in Part Three-III below) or in the one-year budget examinations (discussed in Part Four-III(A) below). Consequently, the Commission approves each amount proposed by PREPA. As set forth on Attachment 1, those amounts are:

—CILT: $51.784 million

—Public lighting: $93.241 million

—All remaining subsidies: $37.901 million[203]

The Commission here offers brief comments on two of these items. Remaining comments about their appropriate treatment appear in Part Three-IV.

CILT

253. PREPA has proposed CILT amount of $51.784 million. PREPA claims that this amount reflects $20 million in CILT savings, reflecting among other things PREPA's collections from for-profit businesses conducted by municipalities, as well as charges to municipalities for electricity consumption above the statutory cap (below which municipalities are not charged for consumption).

254. Historically, PREPA has recovered the CILT through a 0.89 factor in the denominator of its Fuel and Purchased Power Adjustors. The Legislature has prohibited this approach. Consequently, PREPA proposes to recover this amount through a separate "rider." This item is reflected in Attachment 1 at line 14.

Directive

PREPA shall provide to the Commission a report describing its efforts to bill and collect from municipalities in regard to the consumption of electricity at for-profit businesses affiliated with such municipalities.

Irrigation District

255. The "Irrigation District" is a division within PREPA that sells water. It consists of (1) the Guayama and Juana Díaz Irrigation Districts, in the south (PREPA refers to these as "SOUCO" and has grouped them together in its calculation of the subsidy); (2) the Valle de Lajas Irrigation District, in the southwest; and (3) the Isabela Irrigation District, in northwestern Puerto Rico. According to PREPA, 48% of the water produced by the Irrigation

203 This number reflects the elimination of $37.041 million due to the double-counting discussed in Part Two-I above and $129,000 for reclassification of the Direct Debit Credit as an Operating Expense, as discussed in Part Three-IV. *See* also Attachment 2 and Attachment 3, page 10.

District is used to serve bona fide agriculture clients, whereas 50% is sold to PRASA. The remaining 2% is sold to commercial and industrial clients.

256. The rates for the agriculture clients are set by law.[204] For non-agriculture clients, the Irrigation District sets its rates by, in the words of PREPA's Mr. Rivera, PREPA's Superintendent of Planning and Research, "negotiating" with its customers. When the Irrigation District's water rates fail to cover its costs, PREPA makes up the difference by raising rates to its electric customers—customers who are excluded from the negotiations.[205] This difference is known as the Irrigation District Subsidy. PREPA projects a FY2017 subsidy of $4.152 million.

257. The arrangement is inefficient and illogical. It is inefficient because non-agricultural water rates should cover their costs, unless a reduction from cost is necessary to ensure that the customer will remain "on the system" to contribute something to fixed costs—a concept we will discuss in the context of the load retention discount at Part Three-II(C)(4). Any departure from cost should be reviewed by the Commission to ensure it is no greater than necessary to retain the customer. It is illogical when two parties "negotiate" a discount whose cost is borne by customers excluded from the negotiations, when this happens the fiscal discipline that normally accompanies negotiations is missing.

258. While the Commission has no choice but to approve the FY2017 subsidy, it will not approve this amount in the future, unless PREPA demonstrates (before the negotiations are complete) that the discount is no greater than necessary and that ICPO and at least one prominent commercial or industrial customer have participated in the negotiations and received all relevant information.

259. Contrary to PRASA's suggestion, the Commission is not asserting jurisdiction over the water sales from PREPA to PRASA. Nor is the Commission affecting the terms of any existing water contracts or intervening in the negotiations over water rates. The Commission is asserting its jurisdiction over PREPA's revenue requirement. PREPA's revenue requirement—and thus the charges electricity customers must pay—are affected by the Irrigation District's deficit. Therefore, the Commission has not only discretion but a duty to ensure that such deficit is reduced to the minimum allowed by the statute. Exercising such jurisdiction over the electricity rates does not amount to exercising jurisdiction over water rates, because it leaves PREPA with the choice of how to eliminate the deficit—

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204 *See* Public Irrigation Act of September 18, 1908, as amended and supplemented by Act 63 of June 19, 1919 and Act 2 of May 31, 1950; 22 L.P.R.A. § 251 et. seq., 22 L.P.R.A. § 301 et. seq. and 22 L.P.R.A. § 341 et. seq., respectively.

205 Although Section 24 of Act 83 of May 2, 1941, as amended, states that the Commonwealth of Puerto Rico will reimburse PREPA for the costs associated to the Irrigation District, several PREPA officials stated during the Technical Hearing that the Commonwealth has not made any reimbursement payments in years.

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reducing its own costs, raising its water rates or transferring its Irrigation District operations to others who can operate them without a deficit. All the Commission is doing is setting electricity rates appropriately.

260. Finally, PRASA's proposal to transfer the Irrigation District to PRASA is outside this Commission's authority.

E. Finance costs

1. Amount of debt service in the revenue requirement

261. PREPA projects debt service of $314 million, consisting of $172 million in principal payments and $143 million in interest payments. This amount is reflected in Attachment 1 at line 19.

262. PREPA's debt falls into two main categories: (1) debt that, on completion of the current negotiations, will be collected by PREPARC through the Transition Charge (known as "Participating Debt"); and (2) all other debt (known as "Legacy Debt"). In this rate case, the Commission has no jurisdiction to address the Participating Debt. We deal here only with the Legacy Debt.[206]

263. A recent report published by the Puerto Rico Commission for the Comprehensive Audit of the Public Credit[207] raises important questions about the reasonableness of certain PREPA debt issuances. However, because PREPA's contractual obligation to pay the interest and principal due on that debt remains, Section 6.25(b) of Act 57-2014 leaves the Commission no choice.[208] With respect to the Legacy Debt, PREPA's revenue requirement for FY2017 must include all principal and interest payments due in FY2017.

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[206] To emphasize the terminology: Some observers have used the term "legacy debt" to refer to all current PREPA debt. That is not an accurate use of the term. We use the term "legacy debt" to refer only to the debt that must be reflected in the portion of PREPA's revenue requirement over which the Commission has jurisdiction. Debt that becomes "participating debt" will be recovered through the Transition Charge collected by PREPARC. While that amount is part of the *total* PREPA revenue requirement, it is not part of the revenue requirement that is subject to our jurisdiction and that is at issue in this proceeding.

[207] *Pre-audit Survey Report of the Puerto Rico Commission for the Comprehensive Audit of the Public Credit*, September 28, 2016.

[208] "The Commission shall approve a rate that: (i) is sufficient to guarantee payment of principal, interest, reserves, and all other requirements of bonds and other financial obligations that have not been defeased as part of the securitization provided in Chapter IV of the Electric Power Authority Revitalization Act, and reasonable costs of providing the services of the Authority ...."

264. To determine the appropriate amount of debt service costs to include in PREPA's FY2017 revenue requirement, PREPA had to make certain assumptions about which bondholders would become Participating Bondholders and which would remain holders of Legacy Debt. PREPA assumed that $700 million of the uninsured bonds would remain as Legacy Debt. This amount is the maximum amount allowed by the Restructuring Support Agreement, as it exists today. PREPA then apportioned that $700 million according to the percentages of the types of debt existing at PREPA prior to the restructuring.[209] The total amount produces a revenue requirement of $314,319,000. Commission Consultant Hill determined that the method by which PREPA made this estimate was reasonable. The Commission accepts it—recognizing that the number is certain to change when the restructuring negotiations are complete. Any divergence of the final number from this estimated number will be addressed in one of the proceedings discussed in Part Four.

265. The discussion of how debt service will affect the revenue requirement does not end here. The final debt costs to PREPA's ratepayers will depend on the application of the Puerto Rico Oversight, Management, and Economic Stability Act ("PROMESA"). Under Section 601 of PROMESA, if a certain percentage of bondholders elects to participate in a debt restructuring, the PROMESA Oversight Board can require the remaining bondholders to participate as well. If that result occurs, the debt now considered Legacy Debt (*i.e.*, the debt associated with the $314 million in debt service) would move out of PREPA's FY2017 revenue requirement and into PREPARC revenue requirement, to be recovered through the Transition Charge. Ratepayers would save money because all the debt, rather than only the Participating Debt, would be subject to the 85% recovery cap, the lower interest rate and the five-year principal holiday called for by the RSA. And to the extent the PROMESA process causes existing Participating Bondholders to accept additional limits on their recovery, ratepayers will also be better off.

266. For these reasons, the Commission orders PREPA to take all actions possible to use the PROMESA process for the advantage of PREPA customers. If and when these changes occur, PREPA shall inform the Commission of the necessary changes to the revenue requirement. On receiving that information, the Commission will determine how and when to adjust the revenue requirement.

[209] See PREPA's response to CEPR-SGH-03-05. For more detail, see the revenue requirements testimony of witnesses Pampush, Porter and Stathos (at 17), along with Schedule F-4-Section IX. There PREPA explains that an estimated $1,595 million of debt is assumed to remain outstanding at PREPA. This amount includes $696 million and $35 million in debt held by the fuel lines and Government Development Bank Letter of Credit, respectively, as well as (i) $700 million of uninsured bonds (the maximum allowed the RSA), and (ii) $164 million of Syncora bonds following the debt service payment of July 1, 2016.

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2. Debt service coverage ratio

267. Attachment 1 calculates the debt service coverage by multiplying the $314 million of FY2017 principal and interest by a debt service coverage ratio of 1.40. That amount, $126 million, is reflected in Attachment 1 at line 21.[210]

268. A debt service coverage ratio ("DSCR") is the ratio of the cash flow available to meet or cover the debt service payments (interest and principal) to the amount of those payments for a particular time period. Suppose a utility's required principal and interest payments in the current fiscal year total $100 million. Suppose further that rates are established such that if the utility sells the amount of electricity projected and its expenditures are the amount expected, its available cash flow will be $120 million. We would say that the utility's actual DSCR is 1.20.

269. Mr. Hill explained that bondholders typically require a DSCR greater than 1.0 because the revenue and expense levels used to compute rates are only estimates. The real world—hurricanes, power plant failures, fuel price increases and economic slowdown—inevitably intervene, causing outcomes to vary from projections. Despite these variances, bondholders still need to be paid. An ample DSCR reduces the risk that the utility will lack sufficient cash flow to pay all of its obligations, including the obligation to its bondholders. That lower risk translates into lower interest rates.[211]

270. There is no "right" DSCR level; rather there is a need to balance the support necessary for a financially healthy utility against the cost to ratepayers.

271. The 1974 Trust Indenture, under which PREPA issues its revenue bonds (bonds in which the borrower's obligation to repay is secured by its revenues), requires a DSCR of 1.20. Part Two-II(B) explained that PREPA's poor financial condition has shut it out of the capital market. Given the need to improve PREPA's financial condition and to begin increasing bondholder confidence, Mr. Hill recommended a DSCR of 1.40 rather than the 1.20 required by the 1974 Trust Agreement. Drawing special attention to PREPA's $2 billion negative net position, he stated:

> [W]hen the investment community loses confidence in the ability of an entity to pay its debts, it is difficult to win back that confidence. Providing only the minimum amount of Debt Service Coverage required by the bond indenture is

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[210] *See* also Attachment 3, page 1.

[211] Mr. Hill noted that according to the American Public Power Association's *Financial and Operating Ratios of Public Power Utilities* (November 2015), the median debt service coverage ratio for long-term debt service for the public power industry is 2.32. For the publicly-owned utilities with more than 100,000 customers, the median DSCR is 1.85.

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not sufficient to signal the investment community that PREPA intends to re-establish its financial position as a reliable lender.[212]

He described the 1.40 DSCR as sufficient to enable PREPA's return to a BBB (investment-grade) rating.

272. Mr. Hill's approach contrasts with that of PREPA's witnesses, who recommended a more expensive 1.57-2.00 DSCR to reach a AA rating. According to Mr. Hill, if the debt service is $314 million, every one-tenth added to the ratemaking DSCR increases ratepayers' cost by $31.4 million. He asserted that PREPA's advisors, by attempting to move PREPA from a C or D rating to A or AA, were not sufficiently considering the effect on ratepayers. At the technical hearing, Mr. Hill used a spreadsheet[213] to show that the PREPA witnesses' proposal would cost the ratepayers more in debt coverage than they would save in interest rate reductions, by a large amount. Given the current low capital costs, this negative benefit-cost ratio was likely to persist. Mr. Hill reasoned that his "more moderate DSCR would improve PREPA's financial position and would also be cost-effective for PREPA's ratepayers while returning PREPA to investment-grade status." He also emphasized that the credit improvement offered by his proposed 1.40 DSCR will be enhanced by the use of the rate procedures described by PREPA Witness Hemphill and Commission consultant Tim Woolf.[214]

273. We agree with Mr. Hill's view that a DSCR of 1.40, well above the minimum 1.20 required by the 1974 Trust Indenture, will signal to the investment community the Commission's support for PREPA's efforts to improve its financial position.

274. Finally, at the technical hearing Mr. Hill and the PREPA witnesses agreed that as long as the revenue requirement includes capital expenditures in current rates (a provision the Commission approved in Part Two-III(C)(7)), there is little practical difference between a 1.40 coverage ratio and a 1.57-2.00 coverage ratio, because the amount of capital expenditure included in the revenue requirement exceeds the amount associated with either coverage level. At such time that including capital expenditures in rates is no longer necessary, however, Mr. Hill's 1.40 DSCR would mean substantial ratepayer savings relative to PREPA's proposed 1.57-2.00.

3. The prospect of renegotiating debt service

275. Some intervenor witnesses argued that PREPA's debt is too high and should be renegotiated downward. These arguments do not have practical value, for two reasons.

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[212] Hill Report at 22.

[213] Commission's Technical Hearing Exhibit 3.

[214] In Part Four, the Commission addresses the Hemphill and Woolf proposals and adopts various budget examination procedures.

276. First, as we detailed in our June 2016 Restructuring Order, PREPA has already obtained from bondholders a 15% reduction in principal, lower interest rates and a five-year deferral of principal. No intervenor presented evidence that PREPA could have obtained more concessions had it bargained more effectively. No intervenor presented evidence that the relationship between PREPA and its bondholders was other than arm's-length. PREPA's lead negotiator was Alix Partners. Ms. Donahue, PREPA's Chief Restructuring Officer, testified at the Technical Hearing that while the bondholders required PREPA to hire a restructuring team, the decision about whom to hire was PREPA's. Alix Partners had to compete against three other companies for the job. No intervenor lawyer cross-examined Ms. Donahue on this point. In a political setting, it may be acceptable to complain about costs. In an administrative adjudication, arguments require evidence. On the question of whether PREPA could have negotiated a better arrangement, intervenors offered no evidence.

277. Second, arguments must be guided by law. While the Commission has authority to approve future debt, it has no authority to adjust the outcome of the PREPA-bondholder negotiations. In administrative litigation, it is the responsibility of attorneys to ensure that expert testimony remains within the legal boundaries that bind the forum. In this instance, some intervenor attorneys failed to heed this responsibility. The Commission expects that this type of professional error will not be repeated.

4. Future bond issuances

278. No longer can PREPA use debt as a means of avoiding rate increases. Debt is appropriate, however, for long-term investments whose value justifies their costs. Oversight of future bond issuances must address their purposes, cost and timing, as well as PREPA's ability to repay. That oversight must be performed by PREPA's Board, the Consulting Engineer and, of course, this Commission. To that end, Section 6(o) of Act 83 provides:

> Except for the bonds and other financing instruments related to the Authority's restructuring pursuant to the agreements entered into with the creditors of the Authority, whose debt parameters shall be governed by the provisions of Chapter IV of the Electric Power Authority Revitalization Act and the Creditors' Agreement, before borrowing any money or issuing bonds for any of its corporate purposes, the Authority shall require the Commission's approval showing that the proposed financing shall be used to fund projects and defray the costs associated therewith in accordance with the Integrated Resource Plan and the Energy RELIEF Plan.

Section 6.3(n) of Act 57-2014 further provides that PREPA shall seek "written approval of the Energy Commission prior to the issue of any public debt." This type of regulatory review of utility debt issuances is common among mainland U.S. regulatory commissions. Also typical is a requirement that the utility submit, along with its request for approval, the following types of information, as all recommended by Mr. Hill:

(1) a prospectus for the debt issue (the document published for investor review of the debt offering); (2) a copy of the supporting Trust Indenture if it is different from the 1974 Trust Indenture under which all of PREPA's revenue bonds currently are issued; (3) a description of any special considerations associated with the new debt issue; (4) if not otherwise provided, a description of the expected yield, the term of the debt, a schedule of payments, and a comparison to current yields of similarly-rated bonds; and (5) five-year financial projections showing that the Company will be able to meet its indenture-mandated debt coverage ratio following the issuance of the new bonds.

The Commission anticipates issuing a rule establishing these requirements, well in advance of PREPA's regaining access to the capital markets.

5. Directives

a. ***PREPA shall include in its FY2017 revenue requirement \$314 million for debt service principal and interest.***

b. ***PREPA shall include a debt service coverage amount of approximately \$126 million, reflecting a debt service coverage ratio of 1.40 applied to the \$314 million in debt service.***

c. ***PREPA shall inform the Commission monthly on its progress regarding financial restructuring, including its efforts to obtain an investment grade credit rating for the new debt to be issued by PREPARC, and its meetings with members of the PROMESA Oversight Board. PREPA shall submit to the Commission copies of any formal presentations that it (or PREPARC) makes to credit rating agencies or to the PROMESA Oversight Board.***

d. ***PREPA shall use all reasonable efforts to persuade the PROMESA Oversight Board to provide the maximum debt service relief available, including demonstrating to that Board how the savings will benefit the Commonwealth's economy and its electricity consumers.***

F. Income from sources other than electricity sales

279. PREPA proposes for its FY2017 revenue requirement Other Income of \$38.925 million. This amount reflects income from sources other than charges for electric service. Examples of Other Income include: non-operating rental income, sinking fund interest income, and other miscellaneous income. This amount reduces the revenues needed to provide electric service. It is reflected in Attachment 1 at line 28.

Directives

1. ***PREPA shall reflect a FY2017 amount of $38.925 million in Other Income.***

2. ***In future years, PREPA shall detail the basis for amounts included as Other Income.***

IV. Calculation of required revenue increase

A. Calculation of revenue requirement

280. The Commission adopts an adjusted base rate revenue requirement (excluding Transition Charge) of $3,413,904,000.[215]

281. To compute the additional revenue required to cover PREPA's needs, we must subtract the revenue it would receive under its current rates, assuming a forecasted level of sales, from the $3.414 billion base rate revenue requirement adopted by the Commission. The difference is called the "deficiency": the amount by which revenues must be increased by increasing rates.[216] As shown on Attachment 1, lines 30 and 31 (Column A), PREPA expects current rates to produce $1.658 billion in fuel and purchased power revenue and $1.078 billion in base rate revenue at current rates, for a total of $2.737 billion (the $2.776 billion on Attachment 1, line 32 Column A is the sum of that $2.737 billion plus the "Other Income" of $38.9 million). We then increased that amount by the $461.3 million in additional fuel costs projected by Drs. Fisher and Horowitz, to produce a revenue requirement (not counting the amounts covered by the Transition Charge) of $3.237 billion.[217]

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[215] See Attachment 1, l. 26, Column C. To the original consultant-proposed figure of $3,406,557,000 (Smith and Dady Ex. 3), we added back the $4,800,000 relating to smart meters (see also Attachment 3, page 2), the $624,000 related to stipulated fines and penalties that had been included in Smith and Dady Ex. 3 based on a miscommunication with PREPA (see also Attachment 3, page 7), the $1,711,000 adjustment relating to reconnection fees (see also Attachment 3, page 9) and reflected a revised amount for Bad Debt Expense resulting from the impact of these other adjustments (see also Attachment 3, page 8). PREPA argued that there was a $643,000 error in the CILT and Subsidy pass through line item. The Commission was not able to verify this, therefore has rejected this adjustment. The Commission has reconciled the CILT and Subsidies amounts as shown on Attachment 4. Such amounts, as adjusted by the Commission, reconcile to the amount reflected in the revenue requirement without any need for PREPA's requested correction.

[216] We discuss the sales forecast in Part Two-IV.B.

[217] See Attachment 1 at ll. 29-32.

282. Comparing this $3.237 billion in current revenues (Attachment 1, line 32) with the Commission-approved revenue of $3.414 billon (Attachment 1, line 26) indicates a revenue deficiency of $177.0 million (as shown on Attachment 1, line 34). That revenue deficiency of $177.0 million is approximately $45.256 million less than PREPA's claimed revenue deficiency of $222.256 million.

283. When the Commission established provisional rates on June 24, 2016, it used PREPA's full proposed revenue requirement (thus raising rates to eliminate an annualized $222.256 million deficiency). Since the deficiency is only $177.0 million, the Commission must return to ratepayers the excess amounts collected from them. We address that subject in Part Two-V. The Commission also needs to determine how to adjust specific rates under specific tariffs produce the new revenue requirement. We address that subject in Part Three-II.

284. Having determined the deficiency in dollars, we now need to determine the increase in existing rates (excluding the Provisional Rate) necessary to eliminate that deficiency. To do so, we need to divide the deficiency by the expected sales (in kWh) to arrive at the necessary cents/kWh increase. We thus turn to the question of sales next.[218]

B. Forecasts of sales and load

1. The significance of sales and load forecasts

285. To satisfy its obligation to serve their customers' needs, a utility must accurately predict those needs. Then customers must pay rates calculated to produce the revenue necessary to serve those needs. Rates result from dividing the revenue requirement by the expected sales. Revenues (in $) divided by sales (in kWh) gives us a rate ($/kWh). Since we have determined the revenue requirement we now must forecast sales.

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[218] Rejecting the proposed revenue requirement, as ICSE-PR recommends, would cause a shortfall of $177,000,000 in PREPA's revenues—at a time when PREPA needs much more, as detailed by Drs. Fisher and Horowitz. It would leave PREPA unable to pay its bondholders, thereby weakening the agreement under which the bondholders have pledged not to declare default and sue PREPA for nonpayment. It would signal that this Commission fails to appreciate two realities: that without outside capital PREPA cannot rebuild its system, and that outside capital will not invest in PREPA without confidence that the Commission understands PREPA's financial needs. Our chosen path is careful and gradual: grant revenue increases only on a showing of need, require budgets to ensure appropriate spending of the revenues, investigate performance deeply to cause the necessary change in cultures, establish infrastructure priorities through the IRP process and require revenue requests to reflect the approved IRP, and heed the statutory requirement that rates must produce revenues sufficient to cover the principal and interest owed on outstanding debt. ICSE-PR's position heeds none of these requirements.

286. Utilities typically forecast two distinct things: total sales of electricity (in kilowatt-hours or megawatt-hours), and "peak load" (in megawatts).[219] The sales forecast expresses how much total energy the utility expects to sell over the course of a year. The peak load forecast states the maximum power the utility expects to need to serve all customers at any one time during that year.

287. The sales forecast is the denominator in various fractions used to set rates. Sales tells us the number of units over which a particular cost must be recovered. Where a utility collects its revenue requirement through sales of kWhs, the numerator is the revenue requirement (in $), while the denominator is sales (in kWhs), giving us a rate in $/kWh. When the utility collects its fuel costs through a fuel clause, again the fuel costs are in the numerator (in $) and the sales are in the denominator (in kWh). Predicting sales accurately is crucial to setting rates correctly.

288. An accurate sales forecast is also necessary for utility budgeting. Expectations of total spending on fuel, purchased power, and operations and maintenance all depend on expectations of sales, because increased sales lead to increased costs in in each of those categories.

289. Like other utilities, PREPA uses forecasted sales as an input into PROMOD, the production cost model described in Part Two-III.B above. To calculate the total amount of energy it needs to generate every year, PREPA needs a sales forecast. This information, along with other data such as fuel cost, operating cost and data on generation performance (such as how quickly specific units can ramp up and ramp down) are input into PROMOD. PROMOD then determines an optimal dispatch pattern for the utility generation fleet for a given period. PROMOD also predicts the costs (as well as expected fuel consumption, emissions, and other system behavior) associated with that dispatch pattern. Different sales forecasts lead to different dispatch patterns with different associated costs.

290. Both sales (kWh) and peak (MW) forecasts can thus affect utilities' planning for a variety of periods—days, weeks, months, years and decades. Peak load forecasts are the key input to determinations of resource adequacy. Local or system-wide increases in peak demand can cause the need to install new generation and transmission facilities. Peak forecasts also shape cost of service studies, which affect allocation or revenue responsibility (as discussed in Part Three-I).

2. Acceptance of the forecast for FY2017

291. The Fisher-Horowitz Report (at Part IV) presented an extended critique of PREPA's approach to sales forecasting. The critique questioned the support (in terms of model design and data) for PREPA's forecasts, the accuracies of past predictions, the

[219] Peak load, sometimes called peak demand refers to the maximum amount of power that a utility must supply, to keep the lights on, at any one moment of a year.

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treatment of energy efficiency, the calculation and use of elasticity of demand, and discrepancies between sales predictions and numbers actually used in the revenue requirements model. At the technical hearing, Dr. Horowitz and PREPA personnel had an extensive and deep debate over their contrasting positions.

292. The one agreement was that PREPA's forecast for FY2017 was acceptable. For purposes of this case, therefore, the Commission will accept it. The Fisher-Horowitz Report points that when PREPA forecasts one year ahead or one month ahead, the difference between prediction and actual is small, and comparable to the difference experienced by other utilities. Moreover, the extent PREPA's revenues are affected by incorrect short-term forecasts, corrections can be made in the adjustor clauses and the one-year budget examinations or the three-year rate proceeding.[220] The disagreements concern forecasts over longer periods.

293. With so many immediate issues to address in the short time allowed for this proceeding, it is not possible to resolve the many differences that have arisen over forecast methodology. The dialogue at the technical hearing made clear that PREPA and the Commission will benefit from a deeper exploration. From that deeper exploration, the Commission can establish guidelines for future forecasts. The result will be fewer disagreements and over and greater confidence in PREPA's forecasts. The Commission will address this topic within the next few months.

3. Directives

294. We will adopt the following recommendations from the Fisher-Horowitz Report, but will schedule a technical discussion to give them more precise shape:

a. ***PREPA shall develop a single, reliable, theoretically sound forecasting model for each rate class. Each model should be able to predict adequately historical sales.***

b. ***PREPA shall develop a new sales forecast based on these models prior to submitting to the Commission another planning or rate case.***

c. ***Any changes to PREPA's forecasting models in the future shall be clearly documented and supported by evidence.***

d. ***In submissions relating to forecasts, PREPA shall provide clear, comprehensive, and accurate methodological documentation, including work-papers showing all relevant***

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[220] We will discuss interim rate proceedings in Part Four.

inputs and calculations, along with note sources for all assumptions and hard-coded values.

e. ***All forecasts shall explicitly account for energy efficiency, demand management and demand elasticity, by class and on a total system basis.***

C. Calculation of rate increase

295. PREPA's projected sales are 17,268,325,180 kWh.[221] Therefore, the average rate increase corresponding to the revenue requirement deficiency of $177,000,000 is approximately 1.025 ¢/kWh. The average rate increase will be applied to the energy charge component of the base rate for all PREPA clients, except as described in Part Three-II.

296. Given the many directives and decisions made by the Commission in this Final Resolution and Order, PREPA shall calculate the actual rate increase for each tariff code and provide such information for Commission review and approval no later than February 15, 2017.

Directives

a. ***As part of its compliance filing, PREPA shall submit no later than February 15, 2017 for Commission review and approval, the computation and description of the actual permanent rate increase for each tariff code and the language it will include in each customer's bill explaining the increase.***

b. ***As provided in Section 6A(f) of Act 83, PREPA's permanent rates shall enter into effect 60 days from the date of approval of this Final Resolution and Order.***

V. Reconciliation of the new permanent rate with the provisional rate

A. Commission finding

297. The provisional rates approved by the Commission on June 24, 2016 were based on PREPA's projection of a deficiency of $222.256 million. Since the Commission finds a deficiency of only $177.0 million, the difference of $45.256 million (annualized) must be returned to ratepayers, because the effective date of the new rates was July 27, 2016. How this money is returned to ratepayers is the subject of this subsection (relating to revenue requirement) and Part Three-II (relating to rate design).

[221] PREPA Ex. 3.0 at 39. See also PREPA Ex. 27.00.

298. The Commission's Rate Case Filing Rules at Section 2.02, Request for Provisional Rates, state:

> Pursuant to Article 6.25(e) of Act 57-2014 and Section 6A(f) of Act 83-1941, when issuing a final order establishing permanent rates, the Commission shall order PREPA to adjust its customer's bills in order to credit or collect any difference between (a) the Provisional Rate charged by PREPA during the time period in which such Provisional Rate remained in effect and (b) the permanent rate which the Commission determines should have applied during such time period, so as to ensure that the Provisional Rates were just and reasonable. Such order shall reflect any upward or downward adjustment, effective as of the date the Provisional Rates were established, necessary to ensure the Provisional Rates were just and reasonable.

PREPA has stated that reconciling on an individual customer-by-customer basis would require changes to the customer billing system, costing approximately $130,000 per month. Reconciling on a customer class basis would avoid this nearly $910,000 (seven months times $130,000 per month) cost—a cost which would be borne by ratepayers.

299. The Commission finds that benefits of perfect accuracy in customer refunds are not worth making customers pay this additional $910,000 cost. PREPA shall credit the $45.256 million (annualized) on a customer class basis. The reconciliation will take place starting with the first month the permanent rate will be in effect for the same number of months the provisional rate was in effect. The legal support for this conclusion is discussed next.

B. Legal analysis

300. The Commission must determine whether Section 6A(f) of Act 83 provides specific guidelines and requirements regarding how to adjust customer bills for the difference between provisional rates and permanent rates.

301. Because the Commission approves a Provisional Rate based only on a limited review of information accompanying PREPA's request, that rate will not necessarily be the same as the permanent rate approved after a full evidentiary hearing. The statute therefore requires the Commission to order PREPA to reconcile the difference between the provisional rate and the permanent rate. Reconciling means granting customers a credit to the extent the provisional rate exceeds the permanent rate, or requiring the customers to pay PREPA the difference if the permanent rate exceeds the provisional rate. The question is whether there needs to be a specific reconciliation for each of PREPA's 1.5 million customers or whether the reconciliation can occur for each customer class as a whole.

302. Section 6A(f) of Act 83 states:

> Upon issuing any order after the rate review process, the Commission shall order the Authority to adjust customer's bills to credit or charge any difference

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between the temporary rate established by the Commission and the new rate approved as a result of the rate review process. In the event a person ceases to be a customer during the effective term of the temporary rate, the Authority shall be required to issue a refund and shall be entitled to collect any difference between the temporary rate established by the Commission and the new rate approved as a result of the rate review process.[222]

303. While every customer will receive an adjusted bill, the question is whether the adjustment must address each customer's individual experience or whether the adjustment can be made to each customer class as a whole. The first sentence of Section 6A(f) provides that PREPA shall "adjust customers' bills". In this phrase, "customers'" is a plural possessive, signaling to us that we may make the adjustment for the entire class (the Spanish version, "ajustar la factura de sus clientes" also uses customers in the plural; neither the English nor the Spanish version say "each client"). Although it recognizes that such phrase may be interpreted as a reconciliation on a customer-class basis[223], ICPO argues that Section 6A(f) requires permanent rates to be reconciled with provisional rates on a per-customer basis.[224] ICPO's statement is based on a separate provision within Section 6A(f)—a provision requiring PREPA to refund to a sub-category of all customers—those who leave PREPA's system while the Provisional Rate is in effect. That portion of Section 6A(f) does not relate to whether the reconciliation mechanism must be customer-specific or on a customer-class basis. The purpose of the latter portion of Section 6A(f) is two-fold. First, it ensures that the reconciliation will benefit all customers, whether they are existing customers or whether they are former customers who have left the system after the Provisional Rate entered into effect.

304. Secondly, it distinguishes between existing and former customers for purposes of how PREPA would reimburse or collect any difference between the Provisional Rate and the permanent rate. Section 6A(f) specifically requires PREPA to, in the case of over-collecting (when the Provisional Rates is higher than the permanent rates), *credit* that difference to its current customers. In the case of customers who leave the system, Section 6A(f) provides that, in the case of an over-collection, PREPA would issue a *refund* to the customers. A credit entails a downward adjustment on the customer's bill, while a refund

222 Similar language is found in Section 6.25(e) of Act 57-2014.

223 See ICPO's Legal Brief at 11, footnote 9. During the Technical Hearing, ICPO agreed with PREPA that the statute was broad and did not establish a specific mechanism for achieving the reconciliation methodology. ICPO further agreed that the statute did not require a customer-specific refund. Also, in response to questions from the Commission Staff, ICPO agreed that in determining the adequate reconciliation mechanism, factors like cost, time and resources should be taken into account to determine the reasonableness of a proposed reconciliation. ICPO further stated that, if customer class reconciliation mechanism (as opposed to a customer-specific mechanism) benefited PREPA's customers, then such a mechanism would be allowed under Act 57-2014.

224 *Id.* at 11.

requires PREPA to physically disburse a determined amount of funds. The reason for the distinction is simple. An existing customer has a continuing relationship with PREPA, so PREPA may adjust its customer's bills to credit or collect any difference between rates. With a customer who has left the system, there is no continuing relationship, so there would be no subsequent bill for PREPA to adjust. In those cases, the Legislative Assembly provided that PREPA must issue a refund to such customers. Whether the amount to be reimbursed is calculated on a customer-specific or customer-class basis is irrelevant to how that amount is returned to the customer—either through a credit or a refund.

305. Section 6A(f) provides a simple mandate to the Commission: to ensure that each customer class pays the actual costs incurred by PREPA in providing electric services to that class. The phrase "adjust customers' bills" cannot be interpreted to mean that the Legislative Assembly required PREPA to study the seven-month billing history of each of its 1.5 million customers to calculate the exact amount each customer is entitled to receive or required to pay—especially where the difference between the provisional and permanent rates is small—as it is here. The phrase "adjust customers' bills" refers to the ordinary procedure of PREPA including on its customers' bill the necessary adjustments to credit or collect any difference between rates, and not to the specific process through which that amount is calculated. As such, we hold that Section 6A(f) does not require the Commission to approve a customer-specific reconciliation mechanism.

Directives

1. ***The reconciliation of provisional rates with permanent rates shall commence when the permanent rates are in effect.***

2. ***The reconciliation shall occur over the same amount of months that the provisional rates were in effect.***

3. ***The reconciliation shall apply to the broad customer classes identified in Part Three-I.A., rather than on a customer-specific basis. This approach will save the $130,000 per month that PREPA has estimated would be required to reconcile per-customer.***

4. ***Because of the small size of the difference tween the provisional rates and the permanent rates, the reconciliation shall be done by adjusting the per-kWh charge, rather than by adjusting each element of a customer class's rate structure.***

5. ***As part of its compliance filing, PREPA shall provide, no later than February 15, 2017, the following information: (i) the total amount (in dollars) to be credited to customers, (ii) the allocation among customer classes of the total amount to be credited, and (iii) the amount (in cents/kWh) to be credited to each customer class on every billing cycle.***

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VI. Required improvements in PREPA's financial reporting and related procedures

306. Our review of PREPA's rate request was hampered by the absence of audited financial statements. The latest audited statements are for FY2014. PREPA informed the Commission that it "believes" we will receive the audited statements for FY2015 in January 2017.

307. The absence of current audited statements has several serious implications. First, PREPA's proposal for a "formula rate mechanism" (discussed in Part Four-II below) assumes availability of audited statements by October of each year. Basing annual updates to the revenue requirement on unaudited information risks basing rates on unreliable cost information. Second, the willingness of existing creditors to show lenience on existing loan terms, and of new creditors to grant new credit on reasonable terms, depends on their trusting PREPA's financial statements.

Directives

1. ***PREPA shall take necessary steps to assure that its audited financial statements can be completed and made available on a timely basis.***

2. ***PREPA shall submit to the Commission its Monthly Reports to the Governing Board. In addition, the report to the Commission will include the following:***

   a. ***explain significant variances between (i) budgeted and actual data, and (ii) current and prior year data.***

   b. ***provide information on Labor Costs, including how current month and year-to-date payroll, pensions, OPEBs and other employee benefit costs compare with prior year amounts and current year budgets.***

   c. ***provide information on PREPA's actual debt service coverage ratio.***

   d. ***provide information on the status of PREPA's financial restructuring, including significant events that have occurred during the reporting month.***

3. ***PREPA shall allocate budgets for new initiatives and costs to specific functional areas, according to standards to be determined by the Commission.***

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308. ***Special directive regarding the Consulting Engineer:*** The 1974 Trust Indenture requires that for as long as any bonds issued under that agreement are outstanding, PREPA must retain an independent Consulting Engineer. Section 706 states:

> It shall be the duty of the Consulting Engineers to prepare and file with the Authority and with the Trustee on or before the 1st day of May in each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges and such other advices and recommendations as they may deem desirable.[225]

This broad language requires the Consulting Engineer must provide to PREPA and the Trustee opinions on rates, budgets, bond issuances and financial covenants, as well as the state of the utility's infrastructure and the need for improvements.

309. PREPA's Business Plan proposes to amend the 1974 Agreement to phase out of the Consulting Engineer's role.[226] At the evidentiary hearing, Ms. Donahue and Dr. Quintana clarified that the intent was not to eliminate the role, but to redefine it and find a new Consulting Engineer.

310. PREPA and its bondholders should not eliminate the role of Consulting Engineer. They should, however, find a new entity, because the prior firm failed in multiple ways to inform the PREPA Board and the public about the deterioration of PREPA's finances and of its physical system. Despite the failures of the prior Consulting Engineer, the concept of an independent entity providing analysis to PREPA, bondholders, the Commission and the public is sound and essential. The PREPA Board needs an independent, expert voice, one with a professional obligation to examine PREPA from top to bottom, and to be truthful and candid about what it observes, to opine on the state of PREPA's physical infrastructure and to recommend revenue increases when necessary. All the topics and analyses topics covered by the prior Consulting Engineer should be addressed by the new one.[227]

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[225] 1974 Trust Agreement, § 706.

[226] See Ex. 3.02 at 65.

[227] The Table of Contents to the 40th Consulting Engineers Report (2013) indicates detailed information provided regarding the following aspects of PREPA's operations: Production Plants, Environment, Co-generators, Transmission and Distribution Systems, Technological Systems, General Facilities, Puerto Rico Economy, Econometric Projections, Generation Forecast, Demand-Side Management and Energy Conservation Programs, Capacity Planning, Alternative Energy Sources, Fuel Mix, Energy Sales Forecasts, Rate Schedules, Subsidies and Credits, Selected Rates, Cost of Service, Annual Budget, Revenues, Expenses, O&M Expenses, Net Revenues, Debt Service Coverage, Depreciation, Accounts Receivable, Contributions to the Commonwealth, Financing, Capital Improvement Program, Retirement Funding, Inventories, Insurance, Funding Recommendations, Human Capital, Legal Affairs, PREPA Subsidiaries.

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Directive

As required by the Trust Indenture, PREPA shall retain a Consulting Engineer, different from the one previously engaged. Before recruiting the Consulting Engineer, PREPA shall submit to the Commission a description of the duties and the required qualifications. The Commission may comment on such description, but PREPA shall have full discretion to choose the Consulting Engineer. PREPA shall provide the Commission any information it requires about the functions, activities and reports of the Consulting Engineer.[228]

[228] In its brief, PREPA "opposes this recommendation being part of this rate review, which involves a Trust Agreement matter, and which is inappropriate based on the record and law and unnecessary here." The Commission is imposing this requirement independent of whether it remains in the Trust Agreement. This requirement is not merely a "Trust Agreement" matter; it is a matter of protecting consumers from excess costs, poor financial and operational decision making, deteriorating infrastructure and the myriad of other problems discussed throughout this order. For PREPA's revenue requirement to be just and reasonable, there must be an independent entity reviewing and reporting on its operations, regularly and transparently. The Commission will not approve a rate increase without assuring itself that the money will be spent wisely. That is the benefit of a Consulting Engineer that does its job properly.

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PART THREE:
Revenue Allocation and Rate Design for FY2017

311. As explained in Part Two, the FY2017 revenue requirement represents the total dollars PREPA must receive during FY2017 to pay all its expenses, fund the approved capital expenditures, pay the principal and interest on debt due during the year and have an appropriate debt service coverage ratio. Having determined the revenue requirement, the Commission now needs to set rates, so that PREPA's customers pay the dollars that produce the revenue requirement.

312. Setting the rates involves two major steps: Allocating responsibility for PREPA's revenue requirement among the major customer classes, then designing the rates to be paid by the individual customers within each class. We address those two subjects in Part Three-I (revenue allocation) and Part Three-II (rate design). Part Three-III discusses riders—special mechanisms that recover specific costs outside of base rates. One rider is for "subsidies," the subject we address separately in Part Three-IV. Finally, Part Three-V addresses rate design issues specific to net-metering for customers who own renewable energy facilities.

I. Revenue allocation

A. Classes, tariffs and tariff codes

313. Revenue allocation divides the responsibility for a utility's revenue requirement among the classes of customers. The first step in revenue allocation, therefore, is to divide customers into classes. PREPA, like many utilities, uses the following broad customer classes:

Residential
Commercial
Industrial
Agriculture
Public Lighting
Other Public Authorities (which PREPA sometimes places into the commercial class for presentation purposes).

Within each of these broad classes, customers are assigned to different tariffs, depending on the customers' cost-causing characteristics. PREPA Exhibit 4.0 lists 17 tariffs:

1. GRS (general residential)
2. RH3 (municipal public housing)
3. LRS (low-income residential)
4. RFR (Public Housing Administration tenants)
5. GSS (secondary general service)

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6. GSP (primary general service)
7. TOU-P (time-of-use primary)
8. GST (transmission general service)
9. LIS (large industrial)
10. TOU-T (time-of-use transmission)
11. SBS (standby service)
12. GAS (general agriculture service)
13. PPBB (independent power producer)
14. PLG (public lighting)
15. USSL (some unmetered loads)[229]
16. CATV (cable operator equipment)
17. LP-13 (sports-field lighting)

Most of these tariffs serve only one customer class. The tariffs GSS, GSP, GST and TOU-P all serve customers in multiple classes: commercial, industrial and/or public classes.

314. PREPA (like many utilities) then divides most tariffs into several "tariff codes," reflecting such distinctions as:

1. the size (measured in various ways) of customers on the RH3, RFR, LRS, TOU and LIS tariffs.

2. whether GRS customers are subject to the discount for students, the handicapped and the elderly.

3. whether the GSS, GSP, GST and TOU-P customers are commercial, industrial and/or public authorities.

4. whether the customer uses net metering or storage air conditioning.

5. whether the customer takes standby service, or has a rate discount for new or expanded loads.

6. the end-uses served by public lighting and unmetered loads.

PREPA lists 71 tariff codes, of which 47 have customers. (Schedule G-1, tab Input-1) Overall, then, PREPA has five or six classes, 17 tariffs, and 47 active tariff codes.

[229] Other unmetered loads, mostly for light, are sometimes treated as part of public lighting as sometimes as separate tariffs.

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B. PREPA's cost-of-service study

1. Purpose and organization of a cost-of-service study

315. A central principle of just and reasonable ratemaking, economic efficiency and equity is that costs should be borne by those who cause them. Once a commission determines customer classes, tariffs and tariff codes, the next step is to determine how customers in those various categories cause the utility to incur costs. The starting point for determining cost causation is a cost-of-service-study ("COSS").[230]

316. In determining cost causation, analysts consider the following factors, among others:

1. each class's contribution to the current need for the equipment and services;
2. each class's contribution to the current usage of the equipment or of the services that require the expenditure;
3. each class's contribution to the rationale for undertaking a cost; and
4. how much each class currently uses the service that created a cost in the past.

Using accounting data, load data and other inputs, a COSS estimates cost responsibility by following three steps: functionalization, classification and factor allocation.

1. ***Functionalization*** places each cost within one of the following areas: generation, transmission, distribution, customer service or overhead (this last sometimes called "administrative and general"). These general functions can be subdivided into sub-functions and accounts.

2. ***Classification*** focuses on the forces that drive the utility's need to incur costs. For the costs associated with each function, sub-function or account, classification determines whether those costs are driven by one or more of three categories of factors: demand, energy and the number of customers. Fuel, for example, is classified as energy-related because the need for fuel is driven by the consumption of energy. Generation and transmission are classified as demand-related when these facilities are built for purposes of serving demand (*i.e.*, the combination of all customers' need for power at a

[230] A cost of service study is often called an "embedded cost of service study" because it is based on costs incurred in the past (embedded costs), which costs are necessary to provide service in the present. A generating plant provides service today but its costs were incurred in the past. An embedded cost study thus differs from a marginal cost study, which focuses on costs to be incurred in the future. We will discuss marginal costs in Part Three-II.A below.

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specific point in time). Generation and transmission can also be classified as energy-related if their purpose is to create fuel diversity—for example, to reduce customer exposure to volatility in fuel prices or fuel availability. Meters are usually classified as customer-related, because it is the existence of a customer (rather than the quantity of demand or consumption) that drives the need for a meter.

3. ***Factor allocation*** allocates each category's costs to the various customer classes. Costs that are classified as demand-related (such as generation costs) might be allocated among customer classes based on each class's proportional contribution to the system's annual peak.[231]

317. While a cost-of-service study may be the starting point for allocating revenue responsibility, it is not necessarily the ending point. As Commission consultant Chernick explained:

> A commission need not approve, or even review, a cost-of-service study in any particular rate proceeding. Some regulators review COSSs in every rate case, others review a COSS once a decade. Some regulators select a particular COSS methodology to guide their decisions about rates; others consider several methodologies, without explicitly accepting any one method.[232]

A COSS thus is a guide, not a constraint:

> Even the best cost-of-service study reflects many judgments, assumptions and inputs; other reasonable judgments, assumptions and inputs would result in different cost allocations. In addition, concepts of equity extend beyond the cost-of-service study's assignment of responsibility for causing costs or using the services provided by those costs, to include relative ability to pay, gradualism in rate changes, and other policy considerations.[233]

318. The COSS prepared by PREPA's consultants[234] followed the traditional steps of functionalization, classification and allocation. They actually performed three separate

[231] Alternatives to allocating based on contribution to annual peak include allocating based on the average of a class's 12 monthly coincident peaks or allocating based on a class's non-coincident peak. A class's coincident peak is its contribution to demand at the point in time that coincides with the system peak. A class's non-coincident peak is the demand at the time of that class's peak demand, regardless of whether it coincides with the system peak.

[232] Chernick Report at 36.

[233] *Id.*

[234] PREPA's COSS appears in PREPA Ex. 8.0. Its authors, Mr. Zarumba and Mr. Granovsky, explain that their COSS "is used in the development of rates" that they propose in PREPA Ex. 4.0.

studies: one based on FY2017 on the assumption that the debt restructuring was completed, one based on FY2017 on the assumption that the debt restructuring was not completed, and one based on FY2014.

2. Critique of the COSS

319. Mr. Chernick found multiple problems with PREPA's COSS. A partial summary follows.

a. Problems with load data

320. The amount of generation, transmission and distribution capacity required to serve customers is determined in large part by the aggregate loads on each component of the system. As Mr. Chernick explained, depending on the system and the type of equipment, the loads that drive the need for new capacity may be a few hours a year, a few hours a month, the highest fifty or hundred hours in the year, the average load in several contiguous high-load hours, or total hourly load.[235] To determine how the loads of various customer classes contribute to the need for capacity, utilities typically conduct a load research program. The research develops load profiles for different customer groups.[236]

321. Because PREPA does not have a continuing load-research program, it had to develop load shapes through other means. Mr. Chernick found that PREPA's efforts had the following problems: (1) Data used to develop load shapes came from different years; (2) in certain customer classes, PREPA used the same load shape for both large and small customers, when their load shapes would likely differ; (3) some load shapes were "simulated" (PREPA's words) rather than actually observed; and (4) much of the information essential to reviewing the reasonableness of the load shapes was not available.[237]

b. Problems with demand allocators

322. PREPA did not have information with which to determine various customer classes' contribution to system peak load. PREPA therefore used allocators based on estimates of class non-coincident peak load. Those estimates reflected different peak hours, days and months for different tariff codes. Also, PREPA did not have non-coincident peak data for each customer class for any recent year, so it combined data on load shapes from as early as FY2009 and as late as FY 2014, depending on the tariff code.

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235 Chernick Report at 39.

236 A load profile for a customer class displays that class's load's shape—how the class's demand varies over the hours in a day, week, season or year. Load shape is crucial information because generation must be sufficient to meet load, whatever its shape, at all hours of the year.

237 Chernick Report at 41-43.

323. Even if PREPA had reliable data on non-coincident peak load, there would still be major problems with using non-coincident peak load as an allocator. As Mr. Chernick explained:

> PREPA does not have one generation system for residential customers, another for street lights, another for secondary commercial customers, and so on. The vast majority of transmission lines serve a wide mix of classes. Most distribution substations and feeders also serve a mix of classes. In the real world, customers are mixed together, sharing distribution, transmission and generation resources. The loads that matter are at the times of high loads [on] each line, each transformer, and the generation system, not at the times of the maximum load of a class or tariff code.[238]

The result of these problems is, as Mr. Chernick explained, that PREPA's estimates of class demand allocators do not represent the load characteristics that drive PREPA's costs.[239]

c. Problems with functionalization and classification decisions

324. In the area of functionalization and classification, the COSS had at least five problems:

1. PREPA classified all fixed costs of generation as demand-related. This decision, Mr. Chernick explained, ignores the fact that PREPA incurred some generation costs not to meet demand but to diversify fuel sources, improve the efficiency of fuel use, or reduce emissions of pollutants. Such generation should have been classified to energy. Similarly, PREPA classified the fixed portion of its power purchase contracts to demand. But those contracts also served an energy function, because their costs were driven, at least in part, by a desire to diversify energy sources, access less expensive fuels, and use less fuel per kilowatt-hour generated.

2. PREPA functionalized all transmission to the transmission category, but some transmission lines should have been classified to generation, because they serve a generation function by connecting generators to the system's network. And transmission that is functionalized as generation then should be classified (as between demand and energy), consistently with how the associated generation was classified.

3. PREPA's sub-classification of distribution, between primary and secondary distribution, was not based on real data because the necessary data were not

[238] *Id.* at 44.

[239] *Id.* at 28.

available centrally. The ratio PREPA used (59.5% for primary and 40.5% for secondary) was flawed because those numbers represented the fraction of load served at each voltage rather than cost of the equipment operating at each voltage.

4. PREPA allocated customer-related costs based on a weighted number of customers. The weightings were based on the relative cost of the different meters used by each tariff group. Mr. Chernick explained that there is no necessary relationship between the relative cost of meters and the ratio of the other customer-related costs that various tariff groups cause:

> [T]here is no reason to expect the variation in the average cost of a meter to be a good measure of the difference among classes in other average customer costs. For example, the variation in the average cost of a service drop among classes depends on a number of factors that have nothing to do with the cost of meters—the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service drop [...][240]

Furthermore, PREPA was not able to provide the derivation of the relative meter costs.

5. PREPA functionalized and classified overhead costs based on a single labor factor, even though many overhead costs are unrelated to labor. For example, insurance and finance are related to physical plant; the Energy Commission expense is related to customer payments for electricity whose prices are regulated by the Commission.

3. The Commission's use of the COSS

325. The Commission is fully committed to setting rates that are guided by a COSS in which we have confidence. But the gaps in data and the numerous subjective and debatable judgments in PREPA's COSS, leave us without confidence that the filed COSS describes cost causation accurately. For the Commission to express confidence in PREPA's COSS would imply it would accept a future COSS with the same flaws. That is not the signal the Commission wishes to send. Nor is it possible to "fix" PREPA's COSS in the short time the statutory deadline in this proceeding makes available. Rather, we will conduct a series of technical conferences, within a separate rate design proceeding, to sort through the problems and reach the right balance between perfection and irresponsibility.

[240] *Id.* at 58.

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326. In the meantime, we must set rates, so that PREPA will have the revenues it needs to operate, the investment community will know that PREPA will be able to pay its bondholders, and so the public will have more certainty about its role in PREPA's transformation. And so we must set rates, even in light of the insufficiency of PREPA's COSS.

327. However, we cannot and do not ignore PREPA's COSS. The document is in the record, was presented by professional witnesses, was closely analyzed by Mr. Chernick and intervenors and was vetted through two days of detailed questioning by the Commission. Under these circumstances, we view PREPA's COSS as a guide against which we can test other options.

328. Some may view our candor about the COSS as a defect, and any deviation from perfection as evidence of unlawfulness. But we remind all that this Commission must operate in the real world. The facts are what they are. PREPA is in a transition. One aspect of that transition is that PREPA does not have, or, if it has, it has not produced during this brief 180-day proceeding, all the information necessary to produce a fully trustworthy COSS. The Commission cannot change that fact, any more that it cannot change the fact that PREPA's current rates are insufficient. The reality of transition means that we must view today's rate decision as itself transitional. As PREPA gathers more data and improves its cost causation analyses, we will have a COSS that more surely guides our rate decisions. Until then we must work with what we have.

329. The alternative would be to view the flawed COSS as a constraint on our rate decision. So constrained, we would have to set rates that were admittedly wrong, then correct them later—a practice that would confuse customers, inject unpredictability and reduce confidence in our decisions. The far better decision is the one Mr. Chernick recommends, and the one everyone can understand, as discussed next.

C. The Revenue allocation results

330. A disciplined, credible cost-of-service study should be an input to revenue allocation, but it is only one consideration. Commissions typically vary from the COSS based on such considerations as gradualism, inter-class equity and concerns about retaining major loads. Indeed, PREPA's proposed revenue allocation itself deviates markedly from its COSS. As presented in PREPA's Exhibit 4.0, the percent increase in base rates for each revenue class called for by PREPA's COSS for most classes differs from the percent increase proposed by PREPA for the same class.[241] The numbers are re-displayed here:

Class	COSS	Proposal
All classes	26.5%	26.5%
Residential	60.4%	28.6%

[241] PREPA's Ex. 4.0 at 26.

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Commercial	6.1%	22.1%
Industrial	1.4%	26.2%
Agriculture	92.9%	22.2%
Public lighting	76.5%	76.5%

331. Given the flaws in PREPA's COSS, the Commission needed another basis for allocating revenue responsibility. Mr. Chernick, with forty years' experience in this field, explained that under such circumstances commissions might allocate responsibility for revenue increases using (a) an equal cents/kWh allocator (as the Commission did for the Transition Charge and for the Provisional Rate) or (b) an equal percentage increase for all classes.[242]

332. The Commission adopts Mr. Chernick's recommendation of allocating revenue increase on an equal cent-per-kWh basis with one exception. This approach, besides being straightforward, encourages conservation, and maintains current incentives to invest in renewable energy.

333. Exception: Prior to computing the general cent-per-kWh increase, PREPA shall increase the PPBB revenue requirement by the average increase in the system revenue requirement, excluding the fuel, purchased-power and Transition Charge. This separate treatment ensures that the entities covered by this tariff, AES and EcoEléctrica, pay an appropriate amount. The tariff is for back-up service to these two large fossil power producers. As presently written, it recovers most of its revenue through demand charges, not through per-kWh charges. If we allocate the entire revenue increase to per-kWh charges these two customers avoid nearly the entire increase. Therefore, this tariff class's appropriate share of the revenue increase will be added to the existing charge for back-up service.

334. The remainder of the allowed revenue increase (*i.e.*, the portion not recovered through the PPBB revenue requirement), shall be divided by projected non-PPBB FY2017 sales to yield a general cent-per-kWh revenue increase rate. The revenue allocation for each tariff shall be increased by the revenue increase rate times the projected sales for that tariff.

Directive

1. ***PREPA shall allocate the allowed revenue increase in an equal cent-per-kWh basis with one exception, as discussed below.***

2. ***Prior to computing the general cent-per-kWh increase referenced above, PREPA shall increase the PPBB revenue requirement by the average increase in the system revenue requirement, excluding the fuel, purchased-power and Transition Charge.***

242 Chernick Report at 68.

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3. ***The remainder of the allowed revenue increase shall be divided by projected non-PPBB FY2017 sales to yield a general cent-per-kWh revenue increase rate.***

4. ***The revenue allocation for each tariff shall be increased by the revenue increase rate times the projected sales for that tariff.***

II. Rate Design

335. Having allocated revenue (and the revenue increase) to each class, the Commission must determine how that revenue will be collected from the customers in each class. That is the purpose of rate design. In this section, we address the rate design issues that were disputed among the participants or where criticisms were offered by our consultants. Before addressing individual rate design issues, we discuss the role in rate design played by marginal cost.

A. The role of marginal cost

336. Rate design is built on specific components. The most common components are the hourly energy charge (in cents/kWh) and the monthly customer charge (in fixed dollars). Some rate designs for large customers also have monthly demand charges (in $/kW). Rate designs assign revenue responsibility to individual customers using "billing determinants." Billing determinants are the denominators in the fractions that produce rates (the numerator being the dollars that need to be recovered). Typical billing determinants track the components just mentioned: kWhs (for the portion of the rate structure that assigns revenue responsibility based on consumption), customer months (for the fixed customer charge portion of the rate structure) and monthly maximum demand in kWs (for demand charges).

337. In choosing among these options, regulators seek to ensure fairness among customers within each tariff class, while provide understandable, stable, and efficient price signals. The focus on efficiency leads to an emphasis on marginal cost.

338. Marginal cost is the increase in a company's total cost caused by making one more unit, whether that unit is one more kWh of energy, one more kW of capacity, or one more customer served. A principle of microeconomics is that prices based on marginal cost are more economically efficient than prices that are not. That is, the closer a price is to marginal cost, the more efficient will be a producer's decision to produce and a consumer's decision to consume. The more efficient those production and consumption decisions are, the more resources are available to the economy (and thus the citizenry) as a whole.

339. Due to the importance of marginal costs, utilities typically perform marginal cost studies. As Mr. Chernick explained, these studies estimate the specific marginal costs that are relevant to ratemaking, such as the cost of:[243]

[243] *Id.* at 70-71.

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1. serving one more customer, for each of the various types of customers served;

2. generating or purchasing one more kWh of energy at various times of the day, plus the line losses associated with delivering that energy to the customer;

3. providing enough generating capacity to serve another unit of customer load (*e.g.*, a kilowatt at the coincident peak hour(s)) plus the line losses associated with serving that load in that hour;

4. providing enough transmission capacity to serve another kilowatt of the customer loads driving transmission requirements;

5. providing enough primary distribution capacity to serve another kilowatt of the customer loads driving primary distribution requirements; and

6. providing enough secondary distribution capacity to serve another kilowatt of the customer loads driving secondary distribution requirements.

340. PREPA Exhibit 9.0 is PREPA's marginal cost study. PREPA used the results to guide its proposed rate structures, in the following areas relevant to this Order: setting energy rates[244], setting customer charges[245], justifying its proposed load-retention rider[246], and estimating whether net-metered customers are "subsidized."[247]

341. After analyzing PREPA's marginal cost study, Mr. Chernick identified serious deficiencies, including:[248]

1. dramatically under-estimating fuel prices, and hence marginal energy costs;

2. ignoring the costs of renewable resources required to meet the renewable portfolio standard;

3. assuming that no load-related generation investments are avoidable for 20 years (thus discounting PREPA's proposals to add hundreds of megawatts of capacity starting in 2020);

244 PREPA Ex. 4.0 at 34, 41.

245 PREPA Ex. 15.0 at 67.

246 PREPA Ex. 4.0 at 36.

247 *Id.* at 34-35.

248 Chernick Report at 71-72.

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4. assuming that no transmission investments are avoidable for more than 20 years (thus discounting PREPA's plans to add large amounts of load-related transmission in the next three years);

5. excluding large amounts of load-related distribution investments;

6. assuming that additional distribution plant will not increase operations and maintenance cost; and

7. failing to distinguish between average and marginal losses.

342. At the Technical Hearing we had a useful dialogue on these points and others. The Commission recognizes that PREPA's consultants hold opinions that differ from Mr. Chernick's. Most of these differences we can address in the upcoming rate design proceeding. The ones that affect specific rates at issue in this case we discuss next, in the following categories: residential rates, commercial and industrial rates, lighting and unmetered rates, connection fees, and unbundling.

B. Residential rates

1. Customer charge

343. The customer charge is imposed on every customer every month, regardless of the quantity of consumption. Its purpose is to recover the fixed costs that are necessary to connect and maintain that customer. Mr. Chernick advised that:

> [T]he fixed charge should reflect the cost of having that household (in the case of the residential class) as a customer, even if the customer used zero energy. [...] The fixed charge should approximate the cost of adding a customer without adding load, or the savings when a customer notifies PREPA that service is no longer required. [...] The fixed customer charge should reflect the minimum costs of serving the smallest customers in the class.[249]

The costs recovered through a customer charge typically include the service drop, meter, meter maintenance, meter reading, billing, and customer service.

344. PREPA proposes to raise the fixed charge for the GRS (general residential service) class from the current $3/month to $8/month, while leaving the RH3 and LRS customer (low-income customer) charges at $2/month.[250] PREPA's consultants testified that

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[249] Chernick Report at 101.

[250] The RFR charges for fixed blocks of energy (based on number of rooms in dwelling) are set by Act 69-2009, as amended by Act 22-2016.

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their marginal cost study showed that the full fixed costs of serving a customer who uses no energy is \$14.18/month for single-phase customers (a category that includes most residential customers and all small customers). The \$14.18/month amount comprises carrying charges of \$4.60 for the meter, \$2.94 for the service drop, and \$5.25 for a share of a transformer, plus \$1.38 for meter reading and billing.[251]

345. Mr. Chernick found this amount to be overstated, for at least three reasons:[252]

1. PREPA used a nominal carrying charge of 17.06%, rather than a real carrying charge of 15.26%. Since PREPA will be escalating this estimate over time, the real carrying charge is appropriate here. Correcting that error, holding all else the same, reduces the marginal customer charge to \$12.83/month.

2. PREPA included in the charge a \$370 transformer. Transformer costs are driven by the size and number of transformers, both of which are determined largely by the area and load to be served, rather than the number of customers. Adding a customer without adding load will not normally require a new transformer. Indeed, PREPA's cost-of-service study treats transformers as entirely load-related rather than customer-related; the marginal cost study should do the same. Correcting this error, all else the same, reduces the customer cost to \$8.13/month at the real rate.

3. PREPA included in the charge a \$207 service drop. Small customers in apartment buildings will usually share a service drop. Assuming that an average of just five small residential customers share a larger service drop sized for general-service customers would reduce the marginal customer cost to \$6.69/month to \$6.13/month at the real rate.

346. Mr. Chernick then performed a recalculation showing that the incremental cost to connect, bill, and service a new small customer would be about \$6/month. But he also calculated that the marginal cost of maintaining an existing customer location might be only \$2 or \$3. He recommended a customer charge of \$4 per month.[253]

Directive

The fixed charge for non-subsidized GRS customers shall be raised to \$4.00, which is consistent with Mr. Chernick's recommendations. No other fixed charge shall be changed. The remainder of the revenue allocated to the GRS customers will

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251 PREPA Ex. 15.0 at 6.

252 Chernick Report at 101-03.

253 *Id.* at 103.

therefore be recovered through the consumption (per kWh) charge. By making the decision to consume electricity more expensive, this approach will encourage more energy conservation and more renewable energy.

347. In finding that a $4.00 customer charge is justified by marginal cost considerations (as evidenced by Mr. Chernick's analysis), we have considered PREPA's consultants' concern that placing costs on the kWh charge rather than on the fixed customer charge will leave PREPA at risk of not recovering its fixed costs. PREPA has provided no evidence about the magnitude of this risk. The Commission must make decisions based on evidence, not fears. However, the Commission will examine this question closely in the upcoming proceeding on rate design. Furthermore, PREPA can bring forward evidence of revenue loss in the reconciliation process described in Part Four below.

2. Energy charge

348. Energy charges are usage charges, imposed per kilowatt-hour of consumption. Currently, PREPA charges GRS customers 4.35 cents/kWh for the first 425 kWh of monthly consumption and 4.97 cents/kWh for additional usage. This type of differential, known as "inclining block" rates, is common in other jurisdictions. It is used by commissions to reduce costs for small users and to encourage energy conservation.

349. PREPA proposes to remove that differential. Its consultants argued that the energy charge for each block exceeds the bundled marginal cost.[254] Mr. Chernick responded that the PREPA marginal energy cost study was flawed, as discussed above. Among other concerns he raised, PREPA's study had estimates of marginal energy costs that were lower than PREPA's self-reported FY2016 production costs. The PREPA estimates also reflected fuel costs much lower than those estimated by Drs. Fisher and Horowitz. Moreover, PREPA's estimates also did not account for the fact that certain plants would be operating all month; with the boiler already hot, the incremental fuel costs necessary to raise those plants' production would be lower than normal. Finally, PREPA used a simple average of the hourly marginal costs, rather than a weighted average of hourly prices reflecting the higher marginal costs in higher-load hours. Mr. Chernick also pointed out that the GRS customers using over 425 kWh monthly have a lower load factor (fewer kWh per kW of NCP peak) than the smaller GRS customers, and therefore may be more expensive to serve per kWh. He added that eliminating the inclining-block rate would "slightly reduce conservation incentives for the larger customers, who probably have more opportunities for conservation."[255]

Directive

[254] PREPA Ex. 4 at 41.

[255] Chernick Report at 72.

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The Commission accepts Mr. Chernick's reasoning and his conclusion. PREPA shall maintain the existing cents/kWh differential in the GRS inclining block rate.

3. Fuel discount

350. The Legislature has mandated a fuel discount. The discount rises with the price of oil, up to $30/barrel. The discount is applied to the first 400 kWh monthly usage of eligible residential customers.[256] PREPA has applied this discount to customers in the LRS and RH3 tariffs and the GRS 111 tariff code (which covers the handicapped, the elderly and college students). PREPA currently uses a complicated formula that gives higher discounts per kWh to the smallest customers. PREPA also uses a complicated declining discount, starting at 90% for the smallest customers, which then drops steeply at 101, 201 and 301 kWh/month. The entire discount abruptly disappears at 426 kWh/month, as explained in the Chernick Report at Figure 7 (at 104-105).

351. In this proceeding, PREPA proposes to simplify the discount in various ways. The Commission agrees with the need to simplify.

Directive

PREPA shall restructure the fuel discount for customers on the LRS, RH3 and GRS 111 tariffs, simplified as proposed in PREPA's filing, but modified so that the discount diminishes gradually over 425 kWh, rather than abruptly. The fuel discount shall be phased out from 425 kWh to 500 kWh.

4. Direct debit credit

352. PREPA provides a 10% discount from base rate (*i.e.*, excluding fuel and purchased power), for residential customers who pay their bills by direct debit. PREPA has not provided data on the rationale for the level of the discount or the savings that result. At the technical hearing we learned that the number of customers using this payment method is small.[257]

353. PREPA says that direct-debit billing increases the probability that PREPA receives its funds on time and in full—if there are sufficient funds in the billed account. PREPA also sees benefits in reduced processing costs, and improved cash flow due to increased predictability.

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[256] See Puerto Rico Electric Power Authority Act sec. 22(c), as amended by Act 133-2016.

[257] CEPR-PC-04-27 at 13. Commission's Sixth Request of Information (July 29, 2016).

354. Mr. Chernick pointed out that whatever the benefits to PREPA of prompt, reliable and efficient payment, those benefits would be the same for all components of the bill, not just the base charge. Since the direct debit credit has been about 2% of the total bill, he recommended resetting the credit to that level but applying it to the entire bill. That level, he said was consistent with discounts offered by other utilities.[258]

Directives

1. ***The direct-debit discount shall remain as currently established, i.e., as a 10% discount on base rates, excluding all riders.***

2. ***In the rate design proceeding, PREPA shall present a business case that describes the benefits and costs of this discount.***

3. ***PREPA shall add the description of the direct debit discount to its tariff book.***

C. Commercial and industrial rates

1. Demand charge

355. A demand charge applies a rate in $/kW to a customer's maximum rate of consumption in any 15-minute period in the month, regardless of whether the customer's maximum load coincides with period of high load on the system. PREPA proposes major increases in the demand charges for the non-residential classes that current have those charges (tariffs GSP, GST, TOU-P, TOU-T and LIS). The proposed increases are more than twice the increases in the energy charges, and for GSP, over twelve times.[259]

356. Mr. Chernick disagreed with this proposal. Here are three reasons he gave, among others, for why demand charges, as tools for taming customer demand and reducing system costs, are ineffective:

1. "Even a single [customer] failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. This attribute of demand charges erodes the incentive to even try to avoid the charge, since weeks of careful effort can be swept away if the electric water and refrigerator happen to go on simultaneously. Once a customer is aware of having hit a high billing demand for the month, the demand charge offers no

[258] Chernick Report at 105-06.

[259] See, *e.g.*, PREPA Ex. 4.0 at 48.

reward for controlling load any time that the customers load is less that that prior demand."[260]

CEMEX's testimony (at 8-9) noted that demand charges penalize arbitrarily when operating sporadically due to low demand for cement—even if the cement plant operates at nearly 100% capacity factor for the days it is used.

2. Customers reach their maximum monthly loads at a wide variety of times during the month, while capacity costs for the system as a whole are driven by coincident loads that occur at the time of maximum system demand on the relevant piece of equipment. So penalizing an individual customer for its non-coincident demand does not help avoid system costs.[261]

3. Customers can avoid demand charges merely by redistributing load. And if a customer shifts its load from its own peak to the system peak for a particular piece of equipment, the result is to increase system costs.[262]

357. Intervenor witnesses asserted that demand charges reduce customer incentive to install distributed generation.[263]

358. PREPA also proposed to eliminate certain ratchets and contract demands.[264] Mr. Chernick agreed with that result because (among other reasons) ratchets make it more difficult for customers to control their bills, while diluting incentives to reduce usage in ways that would reduce PREPA's costs.[265]

Directives

1. PREPA shall not increase demand charges for any tariff other than PPBB (as described herein). The revenue increases assigned in this proceeding to

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[260] Chernick Report at 97.

[261] *Id.* at 97-98.

[262] *Id.* at 98.

[263] See, *e.g.*, Previdi Direct at 9, 15-16; Kunkel and Sanzillo Direct at 3, 32-33; Gonzalez Direct at 8; Masses y Artze Direct at 9.

[264] CEPR-PC-04-31. Commission's Sixth Request of Information (July 29, 2016). The ratchet took the form of determining billing demand each month as the highest of (a) the current month's maximum 15-minute demand, (b) 60% of the customers maximum demand in the preceding year, and (c) 60% of a previously established contract demand level. The effect is a ratchet because one year's demand creates a floor for the charge in the next year; *i.e.*, billing demand cannot ever decline.

[265] Chernick Report at 107.

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the other tariffs with demand charges shall be recovered through PREPA's proposed customer charges and through increases in the per-kWh rates.

2. ***PREPA shall increase each component of the PPBB tariff by an equal percentage, computed to recover the revenue increase allocated to this class consistent with the Commission's determination above.***

3. ***PREPA shall eliminate the ratchets and contract demands. They are unnecessarily complex and lacking in cost justification. With these changes, the demand-charge portion of the customer's bill shall be determined solely by the current month's 15-minute maximum demand.***

2. Time-of-use rates

359. PREPA has two tariffs for non-residential time-of-use rates: time-of-use primary (TOU-P) and time-of-use transmission (TOU-T). For the customers using these tariffs, PREPA proposes to (a) allocate most of the rate increase to the demand charges, (b) eliminate the distinctions between on-peak and off-peak demands, (c) slightly reduce the energy charges, and (d) close the rates to new customers. For the two customers currently on the TOU-T rate with standby service (SBS), PREPA proposes to terminate their TOU rates and move them onto the non-TOU GST tariff.

360. Mr. Chernick advised against these changes. CEMEX also expressed concern, recounting its efforts to switch to a time-of-use rate, which efforts met with PREPA's rejection. We agree with CEMEX's argument that keeping the TOU rates open will assist in helping customers to manage their demand and consumption in a way that lends more stability to PREPA's revenues, while supporting the competitiveness and economic development of industrial consumers.

Directive

This labor-intensive, deadline-driven rate case is a suboptimal time to make major changes in rate design, especially where the effects of those changes on various customers is not well-understood. PREPA shall retain Tariffs TOU-P and TOU-T without change in availability, and keep them open for new customers. PREPA shall eliminate the ratchets and contract charges from these tariffs, and increase the on- and off-peak energy charges in each tariff uniformly to recover the allocated revenue increase. We will address the issue of time-of-use rates in the upcoming rate design proceeding.

3. Economic development rate

361. PREPA proposes to offer price discounts, subject to Commission review, through an economic development rider. The order would allow PREPA to provide a negotiated discount for a period of three to five years in exchange for the customer creating new jobs on

the Island. The discount level would be based on the level of employment created and the cost to serve the load.

Directive

> ***PREPA shall not initiate the economic development rate. The Commission does not currently have expertise in job development. The proposal does not address, among other things, the types of jobs or their longevity. Nor does the proposal address the Commission's ability to enforce the job creation requirement against a customer that fails to achieve that requirement. This Commission cares deeply about economic development, and will do all it can within its authority to stimulate it. But decisions of this importance to Puerto Rico's future must be supported by more than vaguely defined riders. We will discuss this option more deeply in the upcoming rate design proceeding.***

4. Load-retention discounts

362. PREPA proposes a load-retention rider. The rider would be available for situations in which a discount is necessary to retain load that would otherwise be lost, provided the discounted rate generated revenues exceeding the incremental cost of serving the load. Such discounts can protect other customers from having to bear the fixed costs that would be left behind should the customer at issue cease to be a customer of PREPA. The discount would not be tied to job creation. Any discount negotiated by PREPA would be subject to Commission approval.

363. Mr. Chernick cautioned that the Commission should establish some guidelines to define the availability of load-retention discounts, so that they do not subsidize large customers at the expense of others, promote inefficient consumption, or deter the economic development of renewable energy.[266] He also stressed that PREPA's estimates of marginal costs, which he asserts are understated, need to be improved before the Commission can have confidence that increased sales due to any discount will benefit other customers.[267]

Directives

1. ***PREPA shall institute a tariff offering load-retention discounts where necessary to retain load. The discounts shall be subject to Commission advance review, not produce rates below marginal cost, shall be no greater than necessary, shall not encourage wasteful consumption, and shall not pose an obstacle to the development of economical renewable energy.***

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[266] *Id.* at 109-10.

[267] *Id.* at 110.

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2. Negotiations between PREPA and customers seeking this discount shall (a) be guided by the foregoing principles and any others the Commission establishes, and (b) include representatives of ICPO to the extent ICPO wishes to participate. This requirement is not intended to exclude others.

5. The PRASA preferential rate

364. The Commission rejects PRASA's proposal. Act 50-2013 established a preferential rate under which PREPA would bill for all electric services provided to PRASA. For fiscal year 2017 forward, Act 50-2013 established a rate of 16 c/kWh. On March 28, 2014 PREPA and PRASA signed an agreement implementing the preferential rate, as well as other relevant terms and conditions. Section 9 of Act 50-2013 authorized PREPA to terminate the preferential rate if honoring such rate affected its ability to meet its financial obligations.[268]

365. On December 29, 2015, PREPA notified PRASA its intention of terminating the preferential rate. The preferential rate was effectively terminated on July 1, 2016.

366. PRASA argues that Act 50-2013 requires the Commission to approve a preferential rate.[269] PRASA's argument is based on the fact that Act 50-2013 requires PREPA to approve a rate and, through Act 57-2014, the responsibility of approving rates was transferred to the Commission, and such transfer of powers included the obligation to implement a preferential rate for PRASA.

367. We hold that Act 50-2013 does not bind the Commission nor does it impose an obligation to adopt a preferential rate for two reasons. Firstly, Section 6.25(b) of Act 57-2014 provides that all of PREPA's rates would remain in effect until they are reviewed by the Commission. We interpret this sentence to mean that any prior arrangement with regards to PREPA's rates is subject to the Commission's review, and the Commission has the power and authority to review and approve, disapprove or modify all of PREPA's rates. Nothing in Act 57-2014 exempts PRASA's preferential rate from this authority nor does it suggest that the Commission's general discretion to approve rates is limited by Act 50-2013.

368. Secondly, PRASA argues that, since PREPA unlawfully terminated the preferential rate agreement, the Commission should interpret that such rate continues to be in effect.[270] However, during legal arguments, PRASA's attorney stated that no court or administrative forum with competent jurisdiction had issued a ruling confirming PRASA's argument and deeming the preferential rate agreement to be in full force and effect.[271] As

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[268] Section 12 of the PREPA-PRASA agreement provides similar language.

[269] *See* PRASA's Legal Brief at 5.

[270] *Id.* at 3.

[271] *See* Technical Hearing Panel I Part 1 Recording, 17:30.

such, the legal reality before the Commission is that the preferential rate agreement is no longer in effect, and has been terminated since July 1, 2016. The Commission cannot presume, nor it is reasonable to do so, that the preferential rate agreement was unlawfully terminated. Such a controversy is not before this Commission's consideration. Accordingly, the Commission concludes that, as of the date of this Order, the preferential rate is not in effect.[272]

D. Lighting and unmetered rates

369. PREPA has proposed a large percentage rate increase for the Public Lighting and most unmetered tariff codes.[273] Its consultants acknowledge that increasing the rates for the Public Lighting tariff will increase the magnitude of the subsidy charge. On the other hand, they say, mitigating the increase to Public Lighting would require larger increases to other customer classes.[274]

Directive

> ***PREPA shall increase each component of the public lighting and unmetered tariffs by an equal percentage, computed to recover the revenue increase allocated to this class consistent with the Commission's determination above. We will revisit these issues in the rate-design proceeding.***

E. Reconnection fees

370. Currently, secondary-voltage customers (480V and below) pay $25 to reconnect service. PREPA says its reconnection cost is $52. High-voltage customers (>480V) pay $100 for a reconnection, while according to PREPA, reconnection costs approximately $500.

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[272] Similarly, during the Technical Hearings, PRASA's witness, Ms. Ramírez stated that PRASA's request was for the Commission to adopt some kind of rate treatment which would provide stability and predictability to PRASA's energy costs. Upon questions from the Commission's Staff, Ms. Ramírez stated that a fixed rate higher than 16 ¢/kWh which would be adjusted on a yearly basis would be acceptable to PRASA. Act 50-2013 provides for a fixed rate of 16 ¢/kWh and does not contemplate any adjustments to such rate on a periodical basis. We interpret this to mean that PRASA's request to this Commission is outside of the scope of Act 50-2013 and would even contradict some of the provisions of Act 50-2013. We view this as consistent with our conclusion that Act 50-2013 does not limit the Commission's discretion is approving rates applicable to PRASA.

[273] PREPA's consultants stated that Tariff USSL is PREPA's tariff for unmetered services (PREPA Ex. 4.0 at 57). But the USSL tariff serves less than 1% of PREPAs unmetered load.

[274] CEPR-PC-11-02(b) at 2. Commission's Thirteenth Request of Information (September 23, 2016).